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Evaluation of Conventional and Advanced Coal Cleaning Techniques

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EVALUATION OF CONVENTIONAL AND ADVANCED COAL CLEANING TECHNIQUES

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(*) Now the Air and Energy Engineering Research Laboratory

ABSTRACT

This report assesses the capability, cost, and environmental effects of coal cleaning to reduce sulfur dioxide emissions. It is the culmination of a four year coal cleaning environmental assessment program directed by the Industrial Environmental Research Laboratory* at Research Triangle Park, N.C. The period of performance for work on this program was from May 1982 through March 1983.

The report includes evaluations of SO_2 emission reductions by cleaning coals on a state and regional basis, descriptions of coal cleaning equipment, calculation of environmental tradeoffs; development of algorithms for coal cleaning capital costs, operation and maintenance costs, and cost-benefit; brief descriptions of advanced coal cleaning processes; summaries of coal and utility industry trends relative to coal cleaning; and development of a utility system-based model for calculating SO_2 emission compliance costs using coal cleaning, blending, and flue gas desulfurization options.

The report notes that 85 percent of SO_2 emission reductions produced by coal cleaning would be attained from coals in the Northern Appalachian and Eastern Midwest regions. For a given coal, the environmental tradeoff is a reduction of 20 to 50 percent in potential SO_2 emissions and 25 to 85 percent reduction in particulate loadings versus a 50 to 150 percent increase in solid waste generation. The capital cost of a cleaning plant is dependent on coal properties, mining method, and plant site factors. O&M costs and cleaning plant feedrate are approximated by a linear relationship. Most benefits of cleaning can be quantified including those associated with boiler performance based upon the results of a recent TVA/DOE study. Several chemical and advanced physical coal cleaning processes continue to look promising for

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16. ABSTRACT

The report assesses the capability, cost, and environmental effects of coal cleaning to reduce sulfur dioxide (SO2) emissions. It is the culmination of a 4-year program directed by EPA's AEERL. The report includes evaluations of SO2 emission reductions by cleaning coals on a state and regional basis; descriptions of coal cleaning equipment; calculation of environmental tradeoffs; development of algorithms for coal cleaning capital costs, operation and maintenance costs, and cost benefits; brief descriptions of advanced coal cleaning processes; summaries of coal and utility industry trends relative to coal cleaning; and development of a utility-system-based model for calculating SO2 emission compliance costs using coal cleaning, blending, and flue gas desulfurization options. The report notes that 85% of the SO2 emission reductions produced by coal cleaning would be attained from coals in the Northern Appalachian and Eastern Midwest regions. For a given coal, the environmental tradeoff is a reduction of 20-50% in potential SO2 emissions and 25-85% reduction in particulate loadings versus a 50-150% increase in solid waste generation. The capital cost of a cleaning plant is quite dependent on the coal, the mining method, and site specific factors. However, a linear relationahip can be developed for O and M costs versus cleaning plant feed rate.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution	Pollution Control	13B
Coal	Stationary Sources	08B, 21D
Coal Preparation	Coal Cleaning	08I
Sulfur Dioxide		07B
Cost Estimates		14A
Coal Mining		

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production of very low sulfur, low ash coals. Generally, the number of coal preparation plants and amount of coal cleaned can be expected to grow substantially in the next ten years. This growth rate will depend largely upon energy prices and EPA policies affecting SO_2 emissions.

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SECTION 1.0

INTRODUCTION

In the mid 1970s the U.S. Environmental Protection Agency, (EPA), Office of Research and Development, sponsored a number of programs to determine the sulfur removal capabilities of various pollution control technologies. One of these was coal preparation, a technology that has been in commercial use for over 50 years. One project, spanning a four year period, investigated technological, economic, and environmental aspects of coal preparation. This document is the culmination of that effort. It contains engineering and scientific data concerning the use of coal preparation for controlling SO_2 emissions from coal burning sources.

Coal preparation, or beneficiation, is a series of operations that remove mineral matter (ash) from coal. Coal preparation uses different mechanical operations including size reduction, size classification, cleaning, dewatering and drying, waste disposal, and pollution control. This type of coal preparation is also referred to as physical coal cleaning (PCC) or simply coal washing.

Coal preparation processes are principally designed to remove ash, enhance energy production, and standardize the product. Sulfur removal is achieved because the ash material contains pyritic sulfur. However, preparation plants are not usually designed to optimize sulfur removal. There are about 500 coal preparation plants in the U.S. (as of 1979, the latest year such data were collected). Over 30 percent of utility coal is cleaned to some degree. The utility industry uses cleaned coal instead of raw coal to provide a higher energy content fuel, to meet emission regulations, and to improve boiler performance and availability. Coal companies clean coal to make it more marketable by improving fuel quality. This, in turn, increases the coal price. Industrial boiler operators use cleaned coal primarily to provide standard fuel sizes and control fines.

This document is divided into seven major sections as follows:

- Section 3.0 -- presents the properties of coal resources throughout the U.S. and characterizes the washability of coal in each state relative to sulfur reduction.
- Section 4.0 -- describes coal preparation equipment including size reduction, size classification, cleaning, and dewatering.
- Section 5.0 -- compares the environmental tradeoffs between discharges at coal preparation plants and reduced emissions from power plants.
- Section 6.0 -- provides a methodology to calculate the capital and operating costs for cleaning plants and algorithms for estimating the benefits achieved by improving fuel quality.
- Section 7.0 -- summarizes current research in advanced cleaning processes.
- Section 8.0 -- presents various opinions and viewpoints on current and future trends relative to coal industry objectives, cleaning philosophy, and equipment capabilities.
- Section 9.0 -- describes a linear programming model developed to simulate fuel choice decisions (raw coal vs. cleaned coal) for an existing utility system as a function of SO_2 emission requirements.

SECTION 2.0

CONCLUSIONS AND RECOMMENDATIONS

This document attempts to summarize information on each major area of direct concern to the U.S. EPA relative to the coal cleaning technology. Each section presents a different facet of the technology including the potential for air pollution reduction, a description of the major unit operations, the environmental impacts from coal preparation, the cost of cleaning and benefits derived from using cleaned coal, evaluation of advanced coal cleaning technologies, and future trends in the coal preparation industry. The document also addresses how a utility can use coal cleaning in conjunction with other commercial SO_2 controls to meet environmental regulations, while satisfying energy demand throughout its system.

2.1 CONCLUSIONS

The conclusions drawn by this comprehensive study of coal cleaning technology are presented below by document section.

Section 3.0 Sulfur Reduction Potential of Cleaning

Based upon coal washability data developed by EPA and the Department of Energy (DOE), the following conclusions can be drawn:

- The percent reduction of the heat specific SO_2 emission parameter from coal washing is about 30 percent for the high sulfur coal regions of Northern Appalachian, Eastern Midwest, and Western Midwest. The percent reduction in the low sulfur coal regions (i.e., Southern Appalachian , Alabama, and Western) ranges from 13 to 22 percent.

- In the Northern Appalachian and Eastern Midwest regions, coal washing can double or triple the amount of coal able to meet moderate (i.e., 2-4 lb $SO_2/10^6$ Btu) sulfur dioxide emission values.

- Coal washing does not measurably increase the amount of coal able to meet the stringent 1.2 lb $SO_2/10^6$ Btu emission standard, except for a few low sulfur coal in reserves in the Southern Appalachian coal region.

- Coal washing can significantly increase the amount of coal from the Northern Appalachian and Western Midwest regions that can be used for compliance with moderate emissions limits mandated by State Implementation Plans (SIPs). For other regions, the increase in compliance coal is less significant.

- Lowering the specific gravity of separation for ash and coal material from 1.6 to 1.4 will generally reduce emissions from high sulfur coal by 10 to 20 percent. However, such a specific gravity reduction will increase coal losses to the refuse stream.

- Emission reductions are sensitive to energy recovery. A 5 percent drop in energy recovery (from 95 to 90 percent) can provide up to a 20 to 30 percent reduction in SO_2 emissions from high sulfur coals. The emission reduction tradeoff is increased coal losses to the refuse stream. An additional 10 to 15 percent reduction in potential SO_2 emissions may be obtained by allowing energy recovery to fall to 80 percent. Low sulfur coals show a 10 percent drop in SO_2 emissions as energy recovery is reduced from 95 to 90 percent; an additional 10 percent reduction in energy recovery can provide a corresponding 10 percent decrease in potential SO_2 emissions.

- In 1979, approximately one-third of all coals used in utility boilers was cleaned. If all utility coals had been cleaned, a total SO_2 emission reduction of approximately 4 million tons would have been achieved. Washing all coals from the Eastern Midwest and Northern Appalachian regions, would have achieved about a 3.5 million ton reduction.

- Cleaning all low sulfur coals (i.e., less than 1 percent sulfur content) would reduce SO_2 emissions by about 0.5 million tons.
- Blending, coal preparation, and coal handling attenuate the variability of run-of-mine (ROM) coal. Cleaned coal is most effective in complying with standards that specify short averaging times and for boilers burning small lot sizes.
- Cleaning coal is one method of controlling trace element emissions from coal combustion.

Section 4.0 Coal Preparation Equipment

- Current coal preparation equipment is capable of removing some of the pyritic sulfur from coal. It is ineffective for the removal of organic sulfur and most fine-grained pyritic sulfur.
- Modern coal preparation equipment is designed primarily for ash removal and product standardization.
- Blending permits an increase in the amount of compliance coal. For very high sulfur coals, coarse washing followed by blending may be the preferred option for marketing such coals. Blending typically costs between $2 and $2.50/ton of product coal.

Section 5.0 Pollution Control and Waste Disposal

- Coal washing reduces SO_2 emissions by 20 to 50 percent and decreases particulate loadings in the flue gas by 25 to 85 percent, while increasing solid wastes by 50 to 150 percent.
- The overall net effect of washing is to partially transfer waste generation from the point of use (i.e., power plant) back to the point of origin (i.e., coal mine and preparation plant). For every ton of SO_2 removed, from 1 to 20 tons of solid waste are generated.
- The major environmental impact from coal washing is generation of large quantities of solid waste equivalent to about 3 to 40 percent of total material mined.

- Pond sediments and coarse refuse have the highest potential for adverse environmental impact based on chemical analyses and bioassay tests of waste stream discharges from coal preparation plants..
- Leachates from solid waste have considerably lower potential for adverse environmental impact than the corresponding solid waste.
- Fine waste slurry and coal pile runoff are potentially hazardous wastewater streams for ecological based criteria, but comply with the most stringent state effluent regulations.
- The quality and pollutant loadings in preparation plant refuse pond waters are remarkably similar to ash pond water quality at power plants.
- Air emissions from coal preparation facilities have a low potential for hazard.

Section 6.0 Cleaning Plant Costs and Benefits

- The approach taken to costing coal cleaning plants must be designed around the specific coal and the desired end results within specified economic constraints.
- Cleaning cost trends are related to level of cleaning (i.e., as coal is cleaned at smaller top sizes, both capital and operating costs increase), plant yield (i.e., as yield decreases, cleaned coal costs increase), and plant size (i.e., economy of scale is operative).
- The major O&M cost components are labor, supplies, fuel and power, and maintenance. A linear relationship can be derived for O&M costs per ton, excluding fuel and power costs:

  O&M cost/ton ($) = -0.0007169 (TPH input level) + 2.945

Section 7.0 Advanced Coal Cleaning

- A major shortcoming of modern fine coal cleaning equipment is its low operating efficiency. For this reason, a number of advanced coal cleaning processes are being developed.

- Promising advanced physical coal cleaning processes under development are the AED process (electrostatic separation technique), OTISCA process (fine coal specific gravity separation using an organic liquid), oil agglomeration (surface property separation using oil in a coal-water slurry), and high gradient magnetic separation (removes weakly magnetic ash materials).

- Non-physical processes in all early states of development include those based on:

  - Microwave treatment
  - Biological treatment
  - Molten caustic treatment
  - Supercritical solvent extraction

- Each advanced coal cleaning process looks favorable in specific applications, so that direct comparisons are not meaningful.

Section 8.0 Future Trends in Coal Preparation

- Of the nearly 600 million tons of coal burned by electric utilities, only about 30 to 40 percent is cleaned. Considerable idle capacity currently exists in the coal preparation industry.

- Coal cleaning is becoming a more economic alternative as coal and transportation costs rise, as coal quality deteriorates due to less selective mining techniques, as utilities need to increase availability and capacity factors, and as pollution control requirements become more stringent.

- The growth of coal cleaning may be slowed by increased availability of western coals, stable oil prices, decreased metallurgical coal demand and slow orders for new coal-fired units.

- Barriers to expanded coal cleaning include the need for: better quality control techniques, improved ash separation techniques, more data on the benefits of cleaned coal on boiler operation, and monetary incentives to use or produce cleaned coal.

- The long term outlook for increased coal preparation may depend upon the ability to produce a low ash, low sulfur slurry product for use in (converted) oil-fired boilers.
- Utilities and state regulatory agencies need more information on quantifying cleaning benefits for fuel choice decisions.
- The trend in preparation plant circuit design is toward more fine coal cleaning and the increased use of heavy medium circuits that results in highly efficient coal-mineral separations.
- The R&D area of greatest short-term emphasis in the preparation industry is improving fine coal washing and dewatering equipment. Long-term R&D will center around development of physical processes for production of low ash, low sulfur fuels and chemical cleaning technologies.

2.2 RECOMMENDATIONS

Most of the available literature, data bases, studies, and ongoing programs concerning coal cleaning were reviewed during development of this technology document. Numerous conclusions could be drawn from the existing knowledge base. However, there are still major data gaps or areas of uncertainty. As a result, the following recommendations are made to improve EPA's overall knowledge of this important SO_2 control technology.

- Update Coal Assessment Processor (CAP) Model. The results in Section 3.0 are based largely on recent DOE washability data applied to results from the CAP model developed by EPA in 1980. This model, which is capable of providing costs for cleaning and SO_2 reduction potentials on a state-by-state basis, still uses data from early 1981 or before. The data bases in the CAP model need to be updated and combined with more recent data obtained from this study, other EPA studies, and studies by DOE, TVA, and the Electric Power Research Institute (EPRI), if it is to be useful in future EPA investigations and programs.

- Validation of Cost Algorithm. In Section 6.0, costs and benefits algorithms were developed for use in future studies of particular coal cleaning plants or circuit designs. These algorithms are based on a limited number of coal cleaning plants (i.e., four plants for capital costs and ten plants for O&M costs). Further validation of these algorithms is needed to better define their applicability and accuracy.
- Further Quantification of Benefits. Section 8.0 points out the need for utilities and state regulatory agencies to better understand the benefits of cleaning coal. Several recent utility studies have shown that cleaning has a lower busbar cost than raw coal for many plants. However, these studies are based primarily on a major study of the TVA system. Other costs benefit claims, such as those related to reduction of generation costs in other utility systems, are not as well documented. Benefits applicable on a national basis have not been fully developed.
- Further Evaluation of Advanced Coal Cleaning Processes. As the advanced processes described in Section 7.0 near commercialization, the EPA needs to better understand how these technologies can be used to reduce SO_2 emissions from coal combustion and what environmental tradeoffs are involved with process implementation.
- Test Fuel Choice Model. The fuel choice model developed to demonstrate the potential uses of coal cleaning as an SO_2 control technology and at what cost is based on a study of one utility system. The model should be tested for one or two more case studies. The results could be compared to study results and costs developed by the utilities themselves.

SECTION 3

PROPERTIES OF U.S. COALS INCLUDING SULFUR DISTRIBUTION AND REMOVAL POTENTIAL

This section presents information on the properties of coal that affect sulfur dioxide emissions. Regional and state summaries are provided that contrast the raw coal properties with their washability potential. The variability of sulfur dioxide emission-related properties and trace element content of coal are briefly discussed as well.

3.1 INTRODUCTION TO COAL PROPERTIES

Coal is a combustible sedimentary rock formed from plant materials and inorganic sediments. Generally speaking, as the coal material ages, the moisture content decreases and the energy content increases; coal rank and properties are therefore a function of the stage of metamorphism. Table 3-1 presents the American Society for Testing Materials (ASTM) coal classes.(1) The "older" coals are classified by dry, mineral-matter-free fixed carbon, the "younger" coals are classified by moist, mineral-matter-free energy content.

Figure 3-1 shows the location of the various types of coal by rank. Most coals east of the Mississippi River are bituminous. There are small pockets of anthracite in Pennsylvania. Most of the coal west of the Mississippi is lower rank coal. Subbituminous coals are predominant in the Rocky Mountain states, and lignites are predominant in North Dakota and Texas. However, significant quantities of bituminous coals are mined in Colorado, Utah, and the Plains States.

Sulfur is a coal contaminant of major concern for air pollution control. Sulfur in coal is found in two major forms: organic and pyritic. Organic sulfur is chemically bonded to the carbon molecules of

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TABLE 3-1. CLASSIFICATION OF COALS BY RANK[a] (ASTM D 388)*

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Class	Group	Fixed Carbon Limits, % (Dry, Mineral-Matter-Free Basis)		Volatile Matter Limits, % (Dry, Mineral-Matter-Free Basis)		Calorific Value Limits, Btu/lb (Moist,[b] Mineral-Matter-Free Basis)		Agglomerating Character
		Equal or Greater Than	Less Than	Greater Than	Equal or Less Than	Equal or Greater Than	Less Than	
I. Anthracitic	1. Meta-anthracite	98	--	--	2	--	--	Nonagglomerating
	2. Anthracite	92	98	2	8	--	--	Nonagglomerating
	3. Semianthracite[c]	86	92	8	14	--	--	Nonagglomerating
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	--	--	Commonly agglomerating
	2. Medium volatile bituminous coal	69	78	22	31	--	--	" "
	3. High volatile A bituminous coal	--	69	31	--	14,000[d]	--	" "
	4. High volatile B bituminous coal	--	--	--	--	13,000[d]	14,000	" "
	5. High volatile C bituminous coal	--	--	--	--	11,500	13,000	" "
						10,500[e]	11,500	Agglomerating
III. Subbituminous	1. Subbituminous A coal	--	--	--	--	10,500	11,500	Nonagglomerating
	2. Subbituminous B coal	--	--	--	--	9,500	10,500	Nonagglomerating
	3. Subbituminous C coal	--	--	--	--	8,300	9,500	Nonagglomerating
IV. Lignitic	1. Lignite A	--	--	--	--	6,300	8,300	Nonagglomerating
	2. Lignite B	--	--	--	--	--	6,300	Nonagglomerating

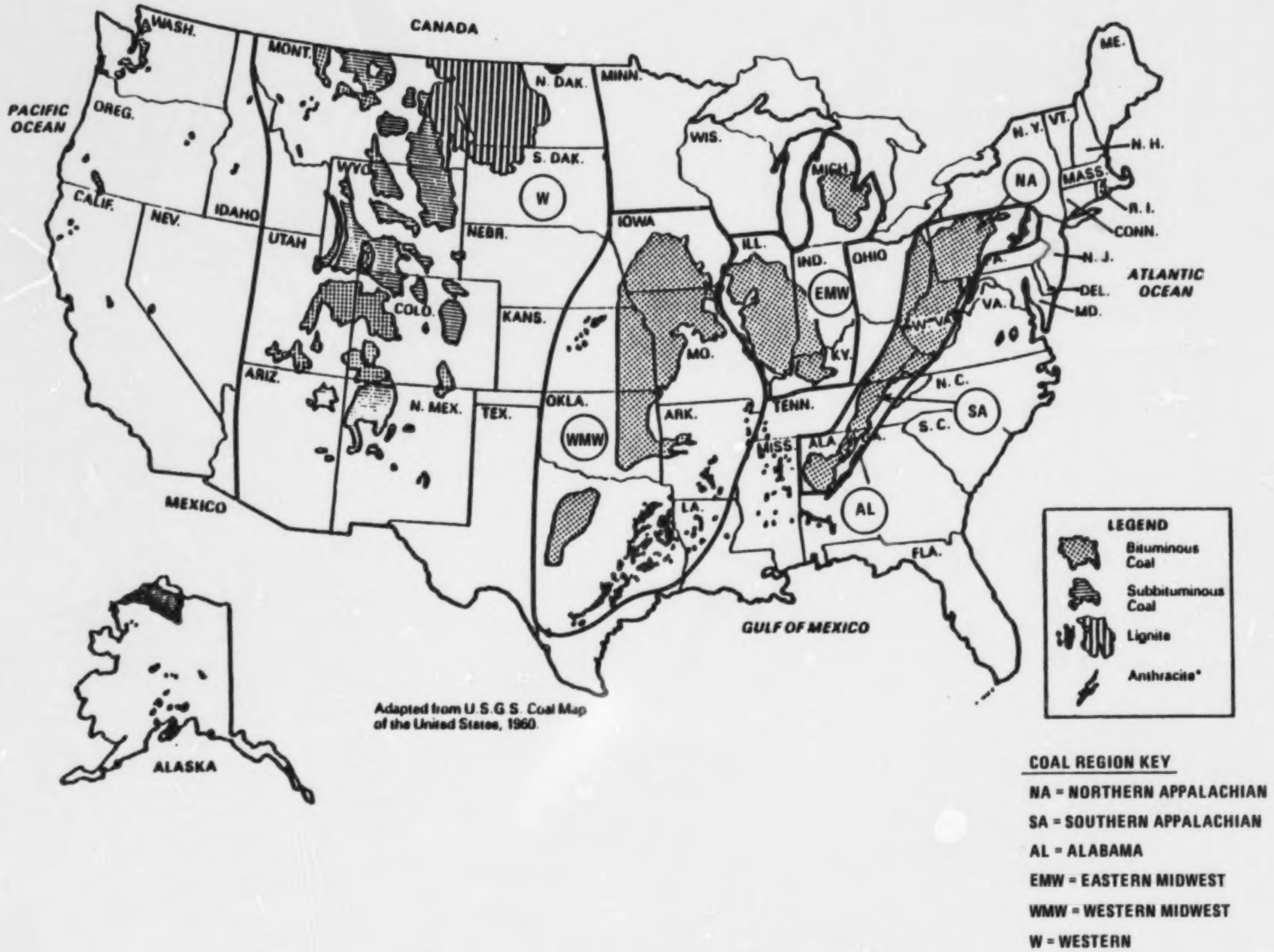
[a] This classification does not include a few coals, principally non-banded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48% dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free British thermal units per pound.

[b] Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c] If agglomerating, classify in low-volatile group of the bituminous class.

[d] Coals having 69% or more fixed carbon on the dry, mineral-matter-free basis are classified according to fixed carbon, regardless of calorific value.

[e] It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high volatile C bituminous group.



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MONT.
WYO.
UTAH
ARIZ.
COLO.
N. MEX.
N. DAK.
S. DAK.
NEBR.
KANS.
OKLA.
TEX.
MINN.
IOWA
MO.
ARK.
LA.
WIS.
ILL.
MICH.
IND.
OHIO
KY.
TENN.
MISS.
ALA.
FLA.
S. C.
N. C.
VA.
W. VA.
PA.
N. Y.
VT.
ME.
N. H.
MASS.
R. I.
CONN.
N. J.
DEL.
MD.
ATLANTIC OCEAN
GULF OF MEXICO
MEXICO
ALASKA
W
WMW
EMW
NA
SA
AL
LEGEND
Bituminous Coal
Subbituminous Coal
Lignite
Anthracite*
COAL REGION KEY
NA = NORTHERN APPALACHIAN
SA = SOUTHERN APPALACHIAN
AL = ALABAMA
EMW = EASTERN MIDWEST
WMW = WESTERN MIDWEST
W = WESTERN

Adapted from U.S.G.S. Coal Map of the United States, 1960.

FIGURE 3-1. U.S. COAL DEPOSITS AND COAL REGIONS

the coal and can only be removed if the bonds are broken by chemical processes. Pyritic sulfur, a mineral, occurs in discrete particles throughout the coal structure. In U.S. coals, the pyritic sulfur may account for from 30 to 70 percent of the total sulfur content. Some of the pyritic sulfur can be removed by commercial methods (a process called washing) that are actually designed to reduce the ash content of the coal. These commercial washing plants can reduce sulfur oxide emissions by 10 to 50 percent depending upon the coal and process employed (see Section 4.3). As a result, washing plants can be used to meet or to assist in meeting sulfur dioxide emission regulations.

Emission limits for coal-fired boilers range from less than 430 ng SO_2/J (1.0 lb $SO_2/10^6$ Btu) to greater than 3900 ng SO_2/J (9.0 lb $SO_2/10^6$ Btu).(4)(5)(6) Older boilers are regulated by SIPs that are generally less stringent than standards for new boilers. New boilers require the use of best available control technology, which means that coal washing cannot be used as the sole technique to comply with these standards.

3.2 REGIONAL AND STATE SUMMARIES OF POTENTIAL SULFUR DIOXIDE EMISSIONS FROM COAL

This section discusses the related topics of coal production, coal washability, and emission standards. The intent is to provide estimates of potential sulfur dioxide reduction in coal regions and states based on coal washability characteristics. The data also illustrates how much additional compliance coal is made available to boiler operators if coal washing is applied. All coal characteristics data presented in this section are on a moisture-free basis.

3.2.1 Data Sources and Methodology

The potential sulfur dioxide emissions estimate for each state is developed by combining 1985 production estimates and average coal characteristics. The production data were taken from EPA Report No. 600/7-81-008, "Coal Resources and Sulfur Emission Regulations: A Summary of Eight Eastern and Midwestern States." (CSER).(2) This EPA report developed 1976 production data from state reports, the 1979 Ohio River Basin Energy Study Report, and Keystone Coal Industry Manuals. The data were updated to 1985 by adding planned production data taken from individual mine expansion plans reported by the National Coal Association and the Department of Energy. The 1985 production data for western midwest and western states were extracted from recent state coal production reports.

Average coal characteristics for each of the eight states included in the CSER report were calculated by assigning average characteristics from specific mines to 1976 production values. The 1985 characteristics were assumed to be the same as 1976 values, except where specific coal characteristics information could be assigned to a planned mine. Coal characteristics for Pennsylvania, Western, and Western Midwest states reflect the ROM coal characteristics data recently developed by DOE/Pittsburgh Energy Technology Center (PETC) in their washability studies. We have assumed that the DOE/PETC coal samples are representative of coal characteristics for 1985 production unless individual state reports indicate otherwise.

The coal washability data base, used in estimating potential sulfur dioxide emission reductions, contains 825 coal samples as reported by the Bureau of Mines in Report RI 8118 and later unpublished supplements.(3) The recently developed data were included in the estimates for Pennsylvania, Ohio, northern West Virginia, and the Western states. Although the data are available for four specific gravities (1.3, 1.4, 1.6, and 1.9) and three top sizes (1 1/2 inch, 3/8 inch, and 14 mesh), Versar has determined in previous studies that the top size of 3.88 cm. (1.5 inches) and specific gravity of 1.6 best represent current commercial capabilities for washing coal. This data point is used to estimate washed coal characteristics for comparison with ROM coal values. For each region, the raw and washed coal characteristics are shown in histogram form in Appendix A to demonstrate how the coal's washability could reduce SO_2 emissions from coal mined in that state. The average raw and clean coal characteristics are combined with production data to estimate the maximum potential sulfur dioxide reduction achievable by coal washing. This value overstates the potential for future sulfur oxide reductions because, nationwide, about one quarter of steam coal is presently washed before combustion. The combined coal characteristics and production data also are compared to the 1971 New Source Performance Standard of 516 ng SO_2/J (1.2 lb $SO_2/10^6$ Btu) and a range of emission values as shown in Table 3-2.

The potential amount of raw and cleaned "compliance" coal available was estimated for the typical metropolitan and rural area SIP emission value for each state. This data is presented in Table 3-3. Again, since some of the coal is already being washed, these values represent the range of compliance coal.

Coal often is used in states other than where it is produced, so that the emissions reduction potential from a producer state is actually spread among several user states. To assess the effect of the coal origin on the emission reduction potential in each state, data was developed on the delivered coal characteristics and origin the state for coal burned in each state (see Appendix A, Table A-20). Most of this information was extracted from the CSER report and was supplemented with utilities delivery data from DOE/EPA Form 423. (Note that the CSER data were also developed from the DOE/EPA Form 423.)

The utilities delivery data includes information on the quantity, cost, and properties (sulfur, ash, heating values) of all coals delivered to utilities in 1979. This data allows an analysis of the quantity of coal available.

3.2.2 Regional Coal Characteristics

Figure 3-1 shows that coal deposits are found in six general regions. These are the Northern Appalachian Region, Southern Appalachian Region, Alabama Region, Eastern Midwest Region, Western Midwest Region,

TABLE 3-2. PERCENT OF COALS MEETING EMISSION VALUES*

	1985 COAL PRODUCTION 10^6 kkg (million tons)	% RAW COAL MEETING EMISSION VALUES LBS. SO_2/106 BTU				% WASHED COAL* MEETING EMISSION VALUES LBS. $SO_2/10^6$			
		<7	4	2	1.2	<7	4	2	1.2
Northern Appalachian Region	188 (209)	76	40	12	5	95	64	25	8
Ohio	48.9 (54)	50	18	3	1	87	30	6	1
Pennsylvania	90.7 (100)	84	49	17	6	99	85	42	13
Northern W. Virginia	48.0 (53)	82	37	3	0	94	63	18	3
Maryland	2.4 (2.7)	91	57	28	12	100	85	41	16
Southern Appalachian Region	216 (240)	100	82	75	40	100	100	90	59
Southern W. Virginia	79 (88)	100	89	81	42	100	100	90	63
Virginia	41.5 (46)	100	100	100	62	100	100	100	88
E. Kentucky*	95.6 (106)	-	-	-	-	-	-	-	-
Tennessee*	8.2 (9)	-	-	-	-	-	-	-	-
Alabama Region	28.8 (32)	100	90	70	30	100	90	70	50

TABLE 3-2. PERCENT OF COALS MEETING EMISSION VALUES (continued)

	1985 COAL PRODUCTION 10^6 kkg (million tons)	% RAW COAL MEETING EMISSION VALUES LBS. SO_2/106 BTU				% WASHED COAL MEETING EMISSION VALUES LBS. $SO_2/10^6$ BTU			
		<7	4	2	1.2	<7	4	2	1.2
Eastern Midwest Region	164 (182)	63	10	3	1	96	30	10	2
W. Kentucky	53.2 (59)	68	3	0	0	100	24	1	0
Indiana	27.8 (31)	78	20	5	5	100	33	15	5
Illinois	83.8 (93)	63	10	5	0	93	30	7	0
Western Midwest Region	71.6 (79)	42	24	14	8	74	28	18	10
Iowa	0.54 (0.6)	14	7	0	0	30	14	7	0
Missouri	5.4 (6)	6	0	0	0	27	0	0	0
Oklahoma	4.5 (5)	79	57	45	36	93	56	49	42
Texas	59.8 (66)	—	—	—	—	—	—	—	—
Arkansas	0.45 (0.5)	—	—	—	—	—	—	—	—
Kansas	0.54 (0.6	—	—	—	—	—	—	—	—

TABLE 3-2. PERCENT OF COALS MEETING EMISSION VALUES (continued)

	1985 COAL PRODUCTION 10^6 kkg (million tons)	% RAW COAL MEETING EMISSION VALUES LBS. SO_2/106 BTU				% WASHED COAL MEETING EMISSION VALUES LBS. $SO_2/10^6$ BTU			
		<7	4	2	1.2	<7	4	2	1.2
Western Region	657 (725)	100	92	81	57	100	100	92	77
N. Dakota	39.9 (44)	100	82	38	5	100	100	40	29
Colorado	34.5 38	100	100	100	94	100	100	100	97
Utah	30.8 (34)	100	100	94	88	100	100	100	96
New Mexico	35.4 (39)	100	100	100	56	100	100	100	94
Montana	68.0 (75)	100	100	93	52	100	100	95	92
Wyoming	448.9 (495)	100	94	90	57	100	100	90	64

* Insufficient number of washability samples to generate meaningful state emission compliance curve

+ Washed coal represents 1 1/2-inch top size and 1.6 specific gravity.

TABLE 3-3. PERCENT COMPLIANCE COAL

	SIP VALUES		% RAW COAL MEETING SIP		% CLEAN COAL MEETING SIP	
STATE	MET	NON-MET	MET	NON MET	MET	NON-MET
Ohio	1.4	4.5	1	23	3	48
Pennsylvania	0.7	3.0	2	57	4	95
Northern West Virginia	2.8	2.8	12	12	34	43
Maryland	1.6	2.6	12	41	25	54
Southern West Virginia	2.8	2.8	87	87	96	96
Virginia	1.4	3.5	85	100	90	100
E. Kentucky	1.2	5.7	28	90	38	100
Tennessee	1.2	4.4	10	20	10	100
Alabama	1.8	4.0	60	90	70	90
W. Kentucky	1.2	5.7	0	20	0	100
Indiana	1.2	---	5	100	5	100
Illinois	1.8	6.0	0	50	5	90
Iowa	5.5	5.5	12	12	24	24
Missouri	2.9	6.4	0	6	0	61
Oklahoma	2.0	2.0	17	17	34	34
Texas	2.0	2.0	24	24	34	34
Kansas	3.0	---	0	100	0	100
Arkansas	1.2	1.2	0	0	0	0
N. Dakota	3.0	3.0	78	78	90	90
Colorado	0.2	0.2	2	2	2	2
Utah	0.2	0.2	0	0	0	0
New Mexico	0.34	1.4	0	100	0	100
Montana	2.0	2.0	77	77	96	96
Wyoming	0.2	0.2	0	0	0	0

and Western Region. The coal data for each of the regions is summarized in Table 3-4. The table presents the number of coal samples analyzed, the raw and washed coal characteristics, and the percent reduction in sulfur dioxide emissions. Table A-1 in Appendix A presents the coal data for the states in which a coal analysis was performed.

Coal cleaning plant design is a tradeoff between top size, extent of cleaning, and energy recovery. The effect of these tradeoffs on emissions is illustrated in Table 3-5. In almost every region, reducing the top size lowers the potential SO_2 emissions from the coal, although the reduction is moderate in most regions. Except for western coals, a more significant reduction in SO_2 emissions is provided by decreasing the specific gravity (equivalent) at which cleaning is accomplished.

Finally, Table 3-5 illustrates the improved fuel quality of the product versus energy recovery. As expected, within the typical operating range of Btu recovery in the cleaning industry (i.e., 95 to 80 percent) the most significant emission reductions (i.e., improved product quality) can be achieved at the cost of losing coal energy value to the refuse stream. The emission reduction over the Btu energy recovery operating range varies from 20 to over 40 percent.

Northern Appalachian Region

The Northern Appalachian Region comprises counties in Ohio, Pennsylvania, northern West Virginia, and Maryland. Northern Appalachian coals are generally medium to high in both pyritic and total sulfur and are therefore very amenable to sulfur reduction by coal washing.

Based on 302 washability samples from this region, about 5 percent of the raw coal samples would meet a 1.2 lbs $SO_2/10^6$ Btu emission standard. The raw coal samples sulfur dioxide emissions parameter ranges from 0.5 to 15.0 lbs of $SO_2/10^6$ Btu with the majority of the coals ranging from 2.5 to 7.5 lbs $SO_2/10^6$ Btu, as can be seen in Figure A-2 in Appendix A. Conventional cleaning (simulated by crushing to 1 1/2" top size and separating at 1.6 specific gravity would allow 8 percent of

TABLE 3-4 SUMMARY OF WASHABILITY EFFECTS BY REGION

		Raw Coal Characteristics			Washed Coal Characteristics*			
REGION	Number of Samples	Heating Value (Btu/lb)	Sulfur (%)	Ash (%)	Heating Value (Btu/lb)	Sulfur (%)	Ash (%)	Percent Reduction (lbs $SO_2/10^6$ Btu)
Northern Appalachia	302	12,740	3.05	14.54	13,574	2.26	8.96	30
Southern Appalachia	37	13,250	1.04	11.4	14,100	0.02	5.8	17
Alabama	10	13,696	1.33	9.5	14,213	1.21	6.09	13
Eastern Midwest	98	12,276	3.86	13.66	13,055	2.86	8.18	30
Western Midwest	72	12,350	4.25	15.3	13,190	3.20	10.31	29
Western	162	13,030	0.79	10.0	12,435	0.67	7.4	22

All values are on a dry basis.

* Washed coal represents 1 1/2-inch top size and 1.6 specific gravity.

TABLE 3-5 SENSITIVITY OF SO_2 EMISSIONS TO CLEANING PARAMETERS

(All Values Shown are in lbs $SO_2/10^6$ Btu)

	Float Fraction		Btu Recovery		
REGION/TOP SIZE	1.6 Sp. Grav.	1.4 Sp. Grav.	95%	90%	80%
Northern Appalachia					
1-1/2 in.	3.2	2.6	4.0	3.1	2.7
3/8 in.	2.7	2.3	3.8	2.7	2.3
14 M	2.4	2.1	3.7	2.5	2.1
Southern Appalachia					
1-1/2 in.	1.3	1.2	1.5	1.3	1.2
3/8 in.	1.3	1.2	1.4	1.2	1.2
14 M	1.3	1.2	1.4	1.2	1.2
Alabama					
1-1/2 in.	1.7	1.5	2.0	2.0	2.0
3/8 in.	1.7	1.5	1.8	1.7	2.0
14 M	1.5	1.4	1.8	1.5	1.7
Eastern Midwest					
1-1/2 in.	4.4	4.0	5.4	4.2	3.9
3/8 in.	4.2	3.8	5.2	4.0	3.7
14 M	4.0	3.6	5.2	3.9	3.6
Western Midwest					
1-1/2 in.	6.1	5.3	7.6	6.2	5.8
3/8 in.	5.5	4.8	7.4	5.9	5.3
14 M	5.2	4.5	7.0	5.8	5.0
Western Region					
1-1/2 in.	0.9	0.9	1.0	0.9	0.8
3/8 in.	0.9	0.9	1.0	0.9	0.8
14 M	0.8	0.8	1.0	0.8	0.8

Basis: Appendices B and C in RI 8118. Composited Washabilities.

the samples to meet a 1.2 lbs $SO_2/10^6$ Btu. The raw and washed coal sulfur dioxide emission parameters are compared in Figure A-4.

Ohio

Ohio generally has a high sulfur coal that is used for steam generation. Most Ohio coals will emit from 4 to 10 lbs $SO_2/10^6$ Btu when burned. Although washing Ohio coal can be quite effective (i.e., 28 percent average reduction in potential sulfur dioxide emission, only 11 percent of the utility coal is currently being washed. Fourteen coal preparation plants are operating in Ohio.

Twice in the past four years, the Ohio legislature has considered passage of a bill for mandatory coal washing of all Ohio coals. The more recent bill died in Committee in April 1982. That bill was intended to "provide a reduction of sulfur dioxide emissions through requiring electric light companies to burn washed coal and through providing such companies incentives to operate coal washing facilities, and to declare an emergency."

Pennsylvania

Pennsylvania bituminous coals are relatively high in sulfur content and therefore benefit substantially by washing. Most Pennsylvania coals will emit from 860 to 3,010 ng SO_2/J (2.0 to 7.0 lbs $SO_2/10^6$ Btu) when burned. Washing Pennsylvania coal can reduce average sulfur dioxide emissions by 40 percent. The 66 coal preparation plants process approximately 30 percent of the utility coal produced in Pennsylvania.

Northern West Virginia

Coal from northern West Virginia is generally medium to high in both pyritic sulfur and total sulfur and is amenable to sulfur reduction by washing. During combustion most coals from northern West Virginia will emit from 1,290 to 3,010 ng SO_2/J (3.0 to 7.0 lbs $SO_2/10^6$ Btu). The 135 coal preparation plants in West Virginia processing approximately 23 percent of the utility coal produced. The washability data indicate a 27 percent reduction in the average sulfur dioxide emission potential.

Maryland

The coal from Maryland also benefits substantially from washing because of its relatively high pyritic sulfur content. The washability data indicate that most raw coals will emit from 860 to 3,010 ng SO_2/J (2 to 7 lbs $SO_2/10^6$ Btu), and washed coal will emit from 430 to 1,720 ng SO_2/J (1 to 4 lbs $SO_2/10^6$ Btu) when burned. This represents about a 32 percent reduction in the average sulfur dioxide emission potential.

Southern Appalachian Region

The Southern Appalachian Region includes coal producing counties in southern West Virginia, Virginia, eastern Kentucky, and Tennessee. It contains coals that are generally low to medium in sulfur content.

Based on 37 coal samples from the Southern Appalachian region (see Figure A-5), about 45 percent of the raw coal samples can meet a 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ Btu) emission standard. Washing these coals can increase the amount of coal that will meet the emission standard by about 20 percent (see Figure A-6). The raw and washed coal sulfur dioxide emission parameters are compared in Figure A-7. Conventional washing processes can remove about 50 percent of the ash material, thus improving Southern Appalachian coal quality. However, because of the low pyritic-to-total sulfur ratio characteristic of these coals, only a 0.1 percent reduction in sulfur content is achieved. In fact, some Southern Appalachian coals will show an increase in sulfur content after washing. The average sulfur dioxide emission parameter is reduced by about 15 percent after washing.

Southern West Virginia

Southern West Virginia coal is relatively low in both pyritic and total sulfur and does not benefit substantially by washing. Approximately 42 percent of the raw coal samples from southern West

Virginia can meet a 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ Btu) emission standard. Most coals from the southern area of the state (82 percent) will emit from 301 to 860 ng SO_2/J (0.7 to 2.0 lbs $SO_2/10^6$ Btu) when burned. Washing these coals can reduce the average sulfur dioxide emission potential by 18 percent. In 1979, 9 percent of the utility coal was washed.

Virginia

Virginia coals are generally low in both pyritic and total sulfur. The coals from this state will emit from 129 to 731 ng SO_2/J (0.3 to 1.7 lbs $SO_2/10^6$ Btu) when burned. The washability data showed about a 7 percent increase in the coal able to comply with a 516 ng SO_2/J standard (1.2 lbs $SO_2/10^6$ Btu). Washing reduced the average sulfur dioxide emission potential by only 9 percent. Although Virginia coals do not benefit greatly from washing, 7 percent of the utility coal produced in Virginia in 1979 was washed.

Eastern Kentucky

The coal from eastern Kentucky is generally low to medium in sulfur. This coal is amenable to sulfur reduction by washing because of the high pyritic to total sulfur ratio characteristic. Eastern Kentucky has 14 coal preparation plants processing approximately 22 percent of the utility coal. The seven washability samples indicated a 17 percent reduction in the average sulfur dioxide emission potential.

Tennessee

The coal from Tennessee is relatively low in sulfur. Washing reduces the ash material in the coal by about 30 percent and the sulfur by about 12 percent. This increase in coal quality represents about a 16 percent reduction in the average sulfur dioxide emission potential.

Alabama Region and State

Based on ten washability samples, Alabama coals are somewhat amenable to sulfur removal by coal washing. About 30 percent of the samples will meet a 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ Btu) as shown in Figure A-8.

Most coals (about 90 percent) from this region will emit less than 1,075 ng SO_2/J (2.5 lbs $SO_2/10^6$ Btu) when burned. Washing the coal will allow 50 percent of the coal samples to meet a 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ Btu) standard. This increase in coal quality represents about a 13 percent reduction in the average sulfur dioxide emission potential. Figure A-10 compares both the raw and washed coal samples sulfur dioxide emission parameters.

Eastern Midwest Region

The Eastern Midwest Region includes western Kentucky, Indiana, and Illinois. The coals in this region are generally high in pyritic sulfur and therefore are very amenable to sulfur reduction by coal washing. The coal sulfur content in terms of the emission parameter ranges from about 430 to 4300 ng SO_2/J (1.0 to 10.0 lbs $SO_2/10^6$ Btu).

Based on 98 washability samples from this region, 1 percent of the raw coal samples will meet a 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ Btu) emission standard. Figure A-12 shows that washing substantially reduces the sulfur emission potential of the coals in the Eastern Midwest Region. The washing process increases the percent of coal samples exhibiting less than 2,580 ng SO_2/J (6.0 lbs $SO_2/10^6$ Btu) from 40 percent to 90 percent. However, washing only increases the percentage of samples able to meet a 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ Btu) emission standard from 1 to 2 percent. A comparison of both the raw and washed coal samples sulfur dioxide emission parameters is presented in Appendix A.

Western Kentucky

Coal from western Kentucky is generally medium to high in sulfur content and can benefit substantially by washing. The coals from western Kentucky will emit from 2,580 to 3,440 ng SO_2/J (6.0 to 8.0 lbs $SO_2/10^6$ Btu) when burned. Washing these coals can reduce the average sulfur dioxide emission potential by 35 percent. Approximately 34 percent of the utility coal produced in 1979 was washed.

Indiana

The coal from Indiana is generally medium to high in pyritic sulfur content. The coal from this state is amenable to sulfur reduction by washing because of its high pyritic sulfur content. Most Indiana coals (65 percent) will emit from 1,720 to 3,440 ng SO_2/J (4 to 8 lbs $SO_2/10^6$ Btu) during combustion. Washing these coals reduces the average sulfur dioxide emissions by 28 percent. Indiana has 14 coal preparation plants processing approximately 52 percent of the utility coal.

Illinois

Illinois coals are very amenable to sulfur reduction by washing. The coals from Illinois will emit from 1,720 to 3,440 ng SO_2/J (4 to 8 lbs $SO_2/10^6$ Btu) when burned. From a potential sulfur dioxide emissions standpoint, washing provides a 30 percent reduction. The emission parameter value is reduced from 2,700 ng SO_2/J in the raw coal to less than 1,900 ng SO_2/J from washed coal. 37 coal preparation plants in Illinois processed approximately 72 percent of the utility coal in 1979.

Western Midwest Region

The Western Midwest Region comprises Iowa, Missouri, Oklahoma, Texas, Arkansas, and Kansas. Generally, this region has coals are medium to high in sulfur content. Iowa, Missouri, and Kansas coals have high sulfur contents, while Oklahoma, Texas, and Arkansas have coals with relatively low sulfur content.

Based on 72 washability samples from the Western Midwest Region, Figure A-14 illustrates that about 8.5 percent of the samples would comply with a 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ Btu) emission standard. After washing, about 10 percent of the samples would comply with a 1.2 lbs $SO_2/10^6$ Btu emission standard as shown in Figure A-15. A comparison of the sulfur dioxide emission parameters for raw and clean coal samples is given in Figure A-16.

Iowa

Iowa coals are generally high in both pyritic and total sulfur and benefit substantially from washing. The coals from this state will emit from 1,720 to 7,740 ng SO_2/J (4 to 18 lbs $SO_2/10^6$ Btu) when burned. The potential emissions from 48 samples range from 4,300 to 6,450 ng SO_2/J (10.0 to 15.0 lbs $SO_2/10^6$ Btu). After washing, these coals would emit from 860 to 5,375 ng SO_2/J (2.0 to 12.5 lbs $SO_2/10^6$ Btu). Washing reduces the average sulfur dioxide emissions by 38 percent. Currently, there are 6 coal preparation plants in Iowa.

Missouri

Coal from Missouri is relatively high in sulfur and is amenable to sulfur reduction by washing. During combustion most coals (94 percent) from Missouri will emit from 2,580 to 5,160 ng SO_2/J (6 to 12 lbs $SO_2/10^6$ Btu). Washing Missouri coal can reduce average sulfur dioxide emission potential by 33 percent. Six coal preparation plants are currently operating in Missouri.

Oklahoma

The coal from Oklahoma is generally low to medium in sulfur content. The coals from this state will emit from 0.75 to 9.5 lbs $SO_2/10^6$ Btu. However, 36 percent of the coals will comply with a 516 ng/J (1.2 lbs $SO_2/10^6$ Btu emission standard). Washing Oklahoma coals can reduce the average sulfur dioxide emission potential by 16 percent. Three coal preparation plants currently operate in Oklahoma.

Texas

Texas coal is relatively low in sulfur. The washability data for the 6 samples (4 bituminous and 2 lignite) indicate a 31 percent reduction in the average sulfur dioxide emission potential. Currently one coal preparation plant is operating in Texas.

Kansas

The coal from Kansas is relatively high in sulfur and is amenable to sulfur reduction by washing. The washability data for the 10 samples indicate a 31 percent reduction in the average sulfur dioxide emission potential.

Arkansas

Arkansas coal is generally low to medium in sulfur content. Washing Arkansas coals can reduce the average sulfur dioxide emission potential by 25 percent.

Western Region

The Western Region includes the states of North Dakota, Colorado, Utah, New Mexico, Montana, Wyoming, and Arizona. It has coals which are typically low in both pyritic and total sulfur.

Based on 162 washability samples from this region, Figure A-17 (Appendix A) shows that about 57 percent of the raw coal samples would comply with a 516 ng SO_2/J (1.2 lbs $SO_2/10^6$ Btu) emission standard. All the coals from this region would emit less than 2,150 ng SO_2/J (5.0 lbs $SO_2/10^6$ Btu) during combustion. After washing approximately 77 percent of the coal would comply with a 516 ng SO_2/J emission standard, and all coals would emit less than 1,720 ng SO_2/J (4.0 lbs $SO_2/10^6$ Btu) when burned. A comparison of the sulfur dioxide emission parameters for the raw and washed coal samples are shown in Appendix A, Figure 19.

Arizona

The six washability samples from Arizona have a mean heating value of 12,394 Btu/lb, a mean sulfur content of 0.49 percent, and a mean coal content of 8.05 percent. Washing the Arizona coal samples increases the mean heating value 2 percent (about 210 Btu/lb), decreases the mean sulfur content insignificantly (0.01 percent), and decreases the mean ash content 1.57 percent. This increase in coal quality represents about a 5 percent reduction in the average sulfur dioxide emission potential.

North Dakota

North Dakota coal is relatively low in sulfur. Most North Dakota coals (80 percent) will emit from 0.5 to 3.0 lbs $SO_2/10^6$ Btu during combustion. Washing the coal from this state can reduce the average sulfur dioxide emission potential by 27 percent.

Wyoming

The coal from Wyoming is generally very low in sulfur and ash and does not benefit substantially by washing. During combustion approximately 96 percent of the coal from Wyoming will emit from 0.2 to 2.2 lbs $SO_2/10^6$ Btu. Washing the coal from Wyoming reduces the average sulfur dioxide emission potential by 11 percent.

Montana

The coal from Montana is generally very low in total sulfur, but does benefit substantially by washing because of its high pyritic sulfur content. The majority of Montana coal (92 percent) will emit less than 3.0 lbs of $SO_2/10^6$ Btu. The average sulfur dioxide emission potential is reduced 29 percent by washing.

Colorado

The coal from Colorado is generally very low in total sulfur and does not benefit substantially by washing because of its high organic sulfur content. All of the coal from Colorado will emit less than 675 ng SO_2/J (1.5 lbs $SO_2/10^6$ Btu) when burned. Washing the coal from Colorado reduces the average sulfur dioxide emission potential by 5 percent.

Utah

Utah coal is very low in total sulfur and also low in pyritic sulfur and therefore does not benefit substantially from washing. Approximately 95 percent of the coal from this state will emit less than 774 ng SO_2/J (1.8 lbs $SO_2/10^6$ Btu) when burned. The average sulfur dioxide emission potential is reduced 10 percent by washing.

New Mexico

The coal from New Mexico is very low in both pyritic and total sulfur and therefore does not benefit substantially from washing. All of the coal samples from New Mexico would emit less than 645 ng SO_2/J (1.5 lbs $SO_2/10^6$ Btu) when burned. The average sulfur dioxide emission potential is reduced 14 percent by washing.

USER STATE ANALYSIS

Coal is mined in only a relatively few states when compared to the number of states in which coal is burned. Table A-20 in Appendix A provides information on:

- The origin state for coal burned in each state in 1979.
- The percentage (by weight) of coal from each origin state.
- The amount of coal burned in each state in 1979.
- The potential order-of-magnitude SO_2 reduction achievable if all coal burned was washed.

Most states use coal originating in 3 to 6 coal-producing states and from several coal producing regions. As a result, regulations involving coal washing or coal use affect each state differently.

The data given in Table A-20 were developed by examination of at least 90 percent of the 1979 coal consumption by utilities in each state. (In some cases, percentages total to more than 100 percent because of rounding.) It is useful to examine the results on both a state and regional basis in light of recent legislation being considered by Congress concerning an 8 million ton decrease in SO_2 emissions from the 31 Eastern U.S. states.

The greatest SO_2 reduction from washing (0.8 million tons per year of SO_2) could have been achieved in Ohio, where approximately 70 percent of the coal consumed comes from the Northern Appalachian region. Virginia, in contrast, receives all its coal from the Southern

Appalachian region, and the absolute reduction would be less than 10,000 tons per year of SO_2. Of course, much more coal is burned in Ohio than in Virginia, but if both states burned the same amount of coal, with other conditions unchanged, Ohio's reductions would still be 7.5 times greater than Virginia's. (In absolute terms, Ohio's reductions would have been almost 80 times that of Virginia's.)

On a regional basis, the midwestern states would have experienced the greatest reduction of sulfur dioxide emissions and the southeastern states the least, with the midwestern states reduction totaling 3.2 times that of the southeastern states. The ratio of reduction for the midwestern states relative to the middle Atlantic states would have been 2.7. Again, the midwestern states burn more coal than either the middle Atlantic or southeastern states. However, if all three regions burned the same amount of coal, with other conditions unchanged, the reduction experienced by the midwestern states in 1979 would still have been 1.2 times that of the middle Atlantic and 1.6 times that of the southeastern states. The mix of coals used in the midwestern states is an important factor in this regard, because much of the coal originates in the Eastern Midwest coal region.

The total absolute reduction for all the states considered, had all the coal been washed in 1979, would have been approximately 4 million tons. Of this total, 3.5 million tons, or 86 percent, of the reduction would have resulted from the washing of those coals which originated in either Northern Appalachia, or the Midwestern state regions. Coals from these regions constituted approximately 62 percent of the coals burned in 1979, some 229 million tons. Thus, upon consideration of the remaining coals, it can be seen that coals from the Southern Appalachia, Alabama, Western Midwest, and Western regions which constituted 38 percent of the coals burned, would have accounted for only 14 percent of the absolute sulfur dioxide reductions from washing all coals in 1979.

3.5 COAL SULFUR VARIABILITY AND EMISSIONS COMPLIANCE

In the above discussions on the amount of compliance coal available in 1985, the values shown may overstate of the actual amount because of the variability in coal characteristics. The ability of a coal to comply with an emission standard is a function of the variability in the coal characteristics, time frame of the emission regulation, and the amount of coal burned (i.e., lot size). For some conditions, the average SO_2 emissions parameter of a compliance coal must be substantially lower than the SO_2 emission limit.

Figure 3-2 graphically illustrates the extent of variability found with ROM coal. Figure 3-3 demonstrates how cleaning the coal reduces the variability, producing a more uniform product.(6) Previous studies sponsored by the EPA indicate that:

- Coal sulfur and ash content vary vertically and laterally within a coal seam and within each mine.
- The variability has a random component, but exhibits some spatial structure.
- Mining transforms spatial variability to temporal variability and, therefore, to some extent, well conceived mining plans can reduce the variability.
- Mining techniques that increase productivity tend to increase variability as well.
- Blending, coal preparation, and coal handling attenuate the variability of the ROM coal characteristics.

Modeling of the coal sulfur emission parameter variability requires a rather sophisticated statistical treatment that must account for the auto correlation (caused by the spatial structure in the mine) as well as the random component.

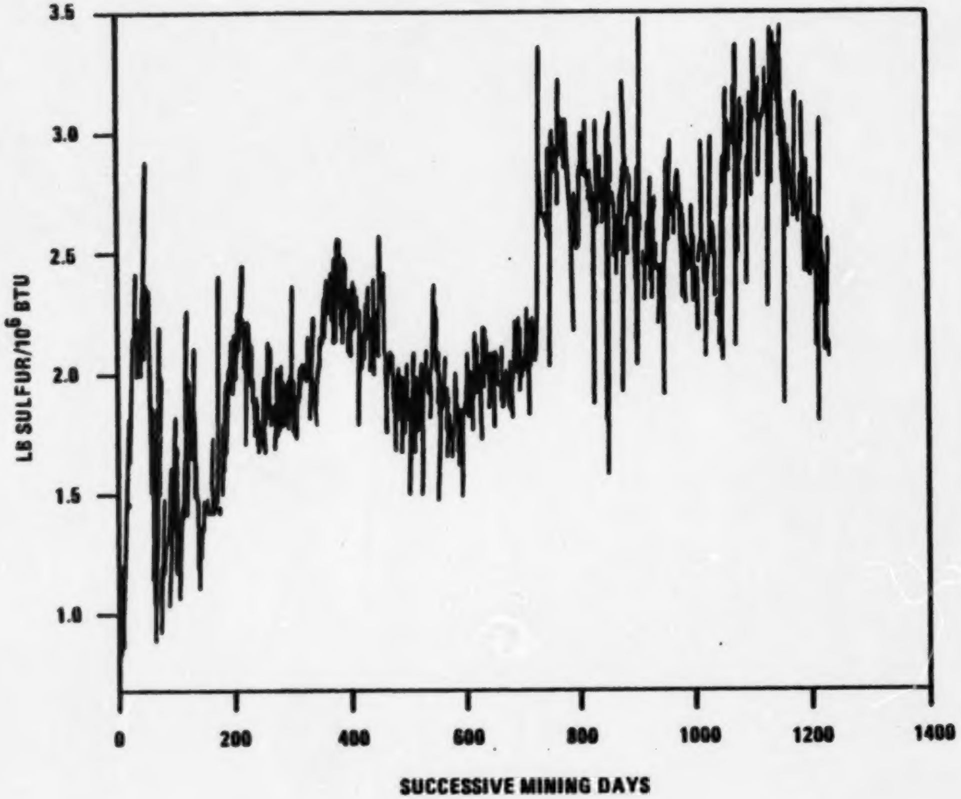
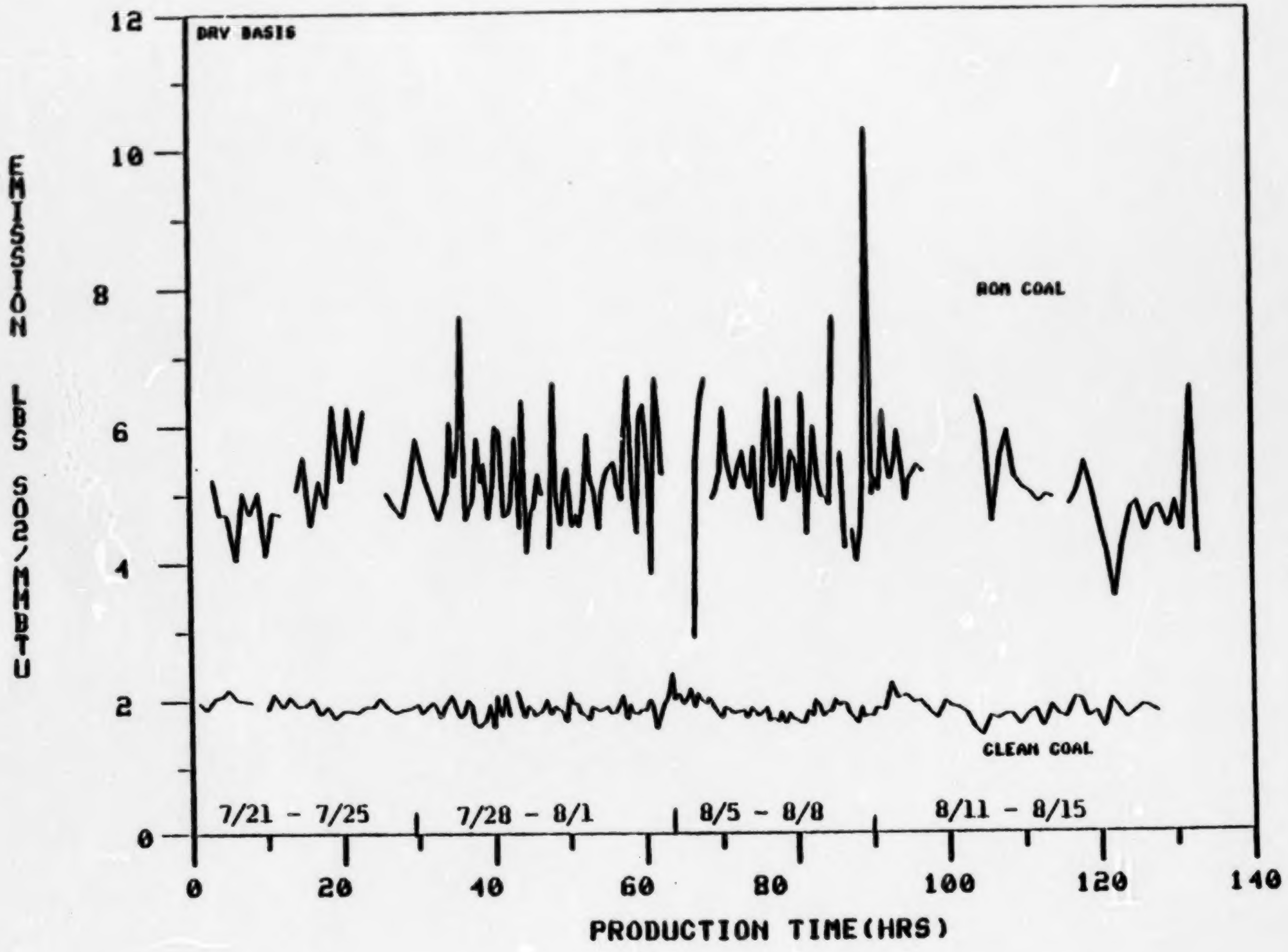


Figure 3-2. **HEAT SPECIFIC SULFUR VALUES FOR HELEN MINE COAL JANUARY 1970 THROUGH DECEMBER 1975**

Figure 3-3. Kitt Mine Preparation Plant - hourly increment sampling data expressed as sulfur dioxide emission rate.



Concerning the last point, if long-term trends in the coal sulfur content are attenuated by blending and/or mining techniques, then auto correlation (which has a short-term component) becomes less significant for longer averaging times. Short-term autocorrelation is important for short-averaging time and small boilers. As a result, the time frame of an emission regulation can affect how variable the emissions are perceived to be. For example, a given coal supply subject to a 3-hour emission averaging period will reflect a greater range of values (variability) than the same coal subject to 24-hour or 30-day averaging times. This can be seen in Figure 3-2 that shows ROM coal data from the Kitt Mine. Using this coal data set, a 3-hour averaging time will produce a maximum emission value of 3,000 ng SO_2/J (7.0 lbs $SO_2/10^6$ Btu); using the same coal data set and a 24-hour averaging time, a maximum emission value of 2,400 ng SO_2/J (5.6 lbs $SO_2/10^6$ Btu) is calculated. This represents a 20 percent reduction in the perceived maximum emission value. During the 140-hour measurement period (approximately 1 week), the average sulfur emission value would be 2,240 ng SO_2/J (5.2 lbs $SO_2/10^6$ Btu).(6)

Similarly, the amount of coal burned during the period of concern (i.e., lot size) affects the variability of the emissions. Small boilers burn less coal than larger boilers over the same time period and will have a greater range of emissions during that period, if both boilers burn the same coal. This relationship is demonstrated in Table 3-6, which shows the effect of averaging (1) time and (2) raw versus cleaned coal characteristics as well as lot size on the variability of sulfur emissions.(7) The table illustrates that cleaned coal has less variability than run-of-mine coal and that this difference is greatest for short averaging times (e.g., 3-hours) and small lot sizes. Conversely, for long averaging times (e.g., 30 days) and large lot sizes, the magnitude of the variability is greatly reduced and there is almost no difference between ROM and cleaned coal characteristics variability.

TABLE 3-6. COMPARISON OF RELATIVE STANDARD DEVIATION WITH CHANGING COAL CHARACTERISTICS, AVERAGING TIME, AND COAL LOT SIZE

Boiler Size	Averaging Time	Coal Lot Size, Tons	Raw Coal $RSD_n^{(1)}$	Clean Coal $RSD_n^{(1)}$
100 MW	3-hr	120	0.200	0.120
	24-hr	960	0.088	0.067
	30-days	28,800	0.017	0.013
500 MW	3-hr	600	0.109	0.080
	24-hr	4,800	0.041	0.032
	720-hr (30 days)	144,000	0.007	0.006

(1) RSD_n = Relative Standard Deviation for n time intervals

$$= RSD_{ref} \times C.F.$$

where: RSD_{ref} is the RSD for a reference lot size or the time increment over which the reference lot size is burned

$RSD_{ref\ RC} = 0.20$ for 120 tons of raw coal
$RSD_{ref\ CC} = 0.12$ for 120 tons of clean coal

C.F. is the correction factor for the auto correlation

$$C.F. = W/.n = \frac{(1-p^2 - 2p/n + 2p \cdot p^n/n)^{1/2}}{n \cdot (1-p)}$$

n = total coal burned divided by the reference coal lot (i.e., 120 tons in this case).

p = the correlation coefficient. For Raw Coal = 0.25; For Clean Coal = 0.5.

As a result of the statistical behavior of the coal characteristics, it is clear that small industrial boilers that must meet emission standards with short time frames generally have the greatest difficulty in maintaining compliance. Large utility boilers that must meet emission standards with long averaging times have less concern about coal characteristic variability relative to emissions compliance. It is important to realize that the mean coal sulfur values needed for compliance must be determined on a case by case basis. A simplified model was used to illustrate the relative importance of coal characteristics, averaging time, relative standard deviation, and autocorrelation. This model can only be used for populations where the long term (monthly) averages do not change. The in-situ coal sulfur content, the mining scheme, and the coal production method used by a coal company will generally result in long term changes in the mean coal sulfur values. The manner in which coal is produced, in fact, may result in a mean sulfur content which changes from month to month. Other models capable of predicting these changes are needed to make predictions when there are long-term variations in the coal supply.

TRACE ELEMENT CONTENT IN COAL

Coal has been found to contain nearly every naturally occurring element. With the exceptions of carbon, hydrogen, oxygen, nitrogen, and sulfur, which are the principal constituents of coal, and iron, aluminum, silicon and the alkaline metals, which are in the ash, most elements are present in trace amounts. Large fractions of many trace elements are associated with discrete mineral phases within the coal structure. Other elements are associated with either the organic constituents (macerals) or finely disseminated mineral phases. The proportions of these components are controlled by the deposition environment and subsequent geological history. Therefore, many coal propOerties, including coal washing characteristics, vary from one coal to another.

Trace elements, specifically mercury, cadmium, lead, arsenic, and selenium, have been considered potentially harmful constituents of coal which might be released during combustion. One means of controlling trace element emissions is to remove the constitutents prior to combustion.

A study recently performed by Bituminous Coal Research, Inc. evaluated coal washing as a means of reducing the level of trace elements in combustion emissions.(8) Twenty samples of ROM coal obtained from the various coal regions throughout the United States were evaluated. The coals were representative of the seam or seams being mined at that site and were selected on the basis of present use or projected use in the near future. All samples were subjected to controlled coal washing at the BCR laboratories. A summary of the conclusions of this study follow:

- Based on the analytical data, significant reductions were obtained in many of the trace and major elements in coal. Washing was particularly effective in the removal of the trace elements arsenic, cadmium, chromium, cobalt, copper, fluorine, lead, manganese, vanadium, and zinc, and of the major elements silicon, aluminum, iron, calcium, magnesium, titanium, sodium, potassium, and phosphorus.
- Differences were demonstrated in effectiveness of removal of trace and major elements from each of the coals, particularly when comparing removal from eastern and western region coals. Most effective removal of trace and major elements was obtained in the coarse-size washing of Eastern region coals and in the intermediate-size washing of the Midwestern region coals. For the Western coals, removal of most mineral constituents was ineffective. This could be attributed to the low initial concentrations of impurities.

- The concentrations of the majority of the elements in coal examined during this study were less than the average concentration of each element in the earth's crust. The exceptions in the washed coals were sulfur, selenium, and, to a lesser extent, chlorine.
- Different elemental associations were found in the washed coal than in the refuse, thereby indicating different mineralogical associations. Also, more strong correlations between elements were found in refuse fractions than in washed coal.
- Variability in trace-element content, even with samples obtained from the same seam, paralleled the variability of sulfur in coal. Such variability apparently results from localized geographical conditions during coal formation.

Table 3-7 presents the average percent removals of the trace and major elements for all 20 samples, for the 12 coal samples from the eastern states, for the 3 samples from the midwestern states, and for the 5 samples from the western states.

In another study 10 coal samples were evaluated for 8 trace elements: cadmium, chromium, copper, fluorine, mercury, manganese, nickel, and lead.(9) It was found that the magnitude of the concentrations of the trace elements varied substantially from coal bed to coal bed within a region and also from region to region. Generally, the data showed that most of the trace elements concentrated in the heavier specific gravity fractions of the coal, indicating that they are associated with mineral matter. Removal of this material should result in significant trace element reductions, ranging from 53 to 88 percent.

Both studies conclude that (1) the coal samples showed a wide range in the levels of trace elements content, (2) most of the trace elements concentrate in the heavier specific gravity fractions, which indicates that they are associated with the inorganic fraction of the coal, and (3) the more effective trace element removal was obtained from the eastern and midwestern coals.

TABLE 3-7. COMPARISON BY REGION OF EFFECT OF WASHING

(Percent Removed of Each Constituent)

		Average, 20 Coals	Average, East*	Average, Midwest**	Average, West+
Product Reject		22	31	14	7
Calorific Value		-26	-37	-16	-4
Ash		56	69	55	27
Total Sulfur		12	4	27	20
Chlorine		-7	-34	-6	24
Pyritic Sulfur		26	25	36	22
Organic Sulfur		-24	-34	-20	-1
Antimony		18	13	-33	35
Arsenic		55	60	51	47
Beryllium		17	24	16	-1
Cadmium		38	36	69	25
Chromium		44	56	42	17
Cobalt		39	33	60	--
Copper		34	41	45	12
Fluorine	Trace Elements	49	62	54	13
Lead		52	58	58	33
Manganese		61	74	69	24
Mercury		27	33	9	23
Nickel		29	34	44	6
Selenium		28	31	22	25
Vanadium		35	51	27	4
Zinc		49	61	62	10
Silicon		58	72	53	29
Aluminum		52	65	51	20
Iron		55	60	58	42
Calcium	Major Elements	41	49	59	9
Magnesium		56	74	67	8
Titanium		51	65	47	19
Sodium		50	64	58	11
Potassium		68	79	62	45
Phosphorus		49	56	88	11

* East: 12 Coal Samples
** Midwest: 3 Coal Samples
+ West: 5 Coal Samples

Negative values indicate enrichment rather than removal.

SECTION 3.0

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SECTION 4

COAL PREPARATION TECHNOLOGY

This section provides an overview of coal preparation technology. Areas discussed include coal washability as it relates to improving the quality of a coal; unit operations and equipment used in preparing coal; performance estimates of coal cleaning operations; environmental discharge and pollution control technologies applied to these discharges; and environmental tradeoffs inherent to coal preparation facilities. There are also brief discussions on the effect of mining techniques on preparation plant performance and on the use of coal blending operations to enhance product coal quality.

WASHABILITY

The potential for improving the quality of a coal by separating mineral components from the coal matrix using differences in specific gravity is called the washability of the coal. A washability analysis evaluates coal characteristics that indicate how easy or how difficult it is to improve the quality of the coal by specific gravity separation. Washability test results are used by coal preparation engineers to estimate the yield and properties of the cleaned coal, to design coal cleaning circuits, and to select coal cleaning equipment.

The washability test procedure consists of a screen analysis followed by a float-and-sink test and a chemical analysis. The first phase in a washability study is a screen analysis. When coal is crushed, the impurities often tend to concentrate more in certain size fractions than in others. The variation in the concentrations of impurities allows the coal preparation engineer to process various size fractions separately.

The screen analysis indicates the percentage of the feed material in each size fraction and is performed by passing coal through a series of screens with decreasing mesh size (The number of open spaces in a screen or sieve per linear inch).

The second phase of a washability study is the float-and-sink tests. These tests are designed to separate each coal size fraction into subsamples at various specific gravities. The specific gravity of most minerals in coal ranges from 2.5 for feldspar ($KAlSi_3O_8$) to about 5.0 for pyrite (FeS_2) while specific gravity of coal ranges from 1.2 to 1.7. The tests are conducted in a series of tanks each containing a liquid at a preselected specific gravity (e.g., 1.30, 1.40, 1.60, and 1.80). Coal from each size fraction is subjected to the lowest specific gravity liquid (e.g., 1.30), and the float material is removed. The sink material is then subjected to a float-and-sink test at the next higher specific gravity (e.g., 1.40) tank. This procedure is repeated until the sink material is tested at the tank with the highest specific gravity (e.g., 1.80). The third phase of a washability study is the chemical analysis. The float and sink materials from each test are first dried and then analyzed (usually) for moisture, ash, heating value, pyritic and total sulfur, and other characteristics. The data is reported either in a tabular form or in a graphical form, as shown in Table 4-1 and Figure 4-1. To perform a washability analysis one must specify the size fractions and specific gravities because there is currently no standardized washability test procedure.

Table 4-1 contains three size and five specific gravity fractions. To produce this data, the coal sample was screened into three size fractions--50.8 x 9.5 mm (2 x 3/8 in.); 9.5 x 0.6 mm (3/8 in. x 28 mesh); and 0.5 mm x 0 (28 mesh x 0). Each fraction was "float-sink" tested at specific gravities at 1.30, 1.40, 1.50, 1.60, and 1.80 (Column 1). The quantity of "float" material (i.e., clean coal at each specific gravity fraction) is weighed (Column 2) and chemically analyzed for ash, heating value, pyritic sulfur, and total sulfur (Columns 3-6). This data is then mathematically accumulated to yield a cumulative value for each

TABLE 4-1. RAW COAL WASHABILITY DATA FOR THE UPPER FREEPORT SEAM

Spec Gravity	Direct					Cumulative Float				
	Weight %	Ash %	Btu/ lb	Pyritic Sulfur,%	Total Sulfur	Weight %	Ash %	Btu/ lb	Pyritic Sulfur,%	Total Sulfur
Size Fraction: 2" x 3/8" (30.0%)										
Float 1.30	38.2	3.4	14589	0.44	0.85	38.2	3.4	14589	0.44	0.85
1.30 - 1.40	24.2	10.1	13613	1.51	2.27	62.4	6.0	14810	0.85	1.40
1.40 - 1.50	8.5	25.2	12011	2.28	2.70	70.9	8.3	13947	1.03	1.55
1.50 - 1.60	4.0	30.7	10566	2.95	3.70	74.9	9.5	13766	1.13	1.67
1.60 - 1.80	4.5	44.7	8837	5.35	5.70	79.4	11.5	13486	1.37	1.89
Sink 1.80	20.6	73.6	3949	8.74	9.03	100.0	24.3	11581	2.89	3.36
Size Fraction: 3/8" x 28 mesh (55.0%)										
Float 1.30	45.8	3.3	14604	0.43	0.85	45.8	3.3	14604	0.43	0.85
1.30 - 1.40	19.2	10.5	13767	0.96	1.50	64.0	5.4	14356	0.59	1.07
1.40 - 1.50	4.5	21.1	12050	1.84	2.20	70.5	6.3	14005	0.67	1.13
1.50 - 1.60	3.5	29.2	10752	2.30	2.80	74.0	7.4	13851	0.75	1.81
1.60 - 1.80	3.1	44.0	8852	3.63	3.90	77.1	8.9	13649	0.86	1.32
Sink 1.80	22.9	72.8	3887	8.71	10.35	100.0	23.5	11414	2.68	3.40
Size Fraction: 28 mesh x 0 (15.0%)										
Float 1.30	46.3	3.0	14649	0.32	0.74	46.3	3.0	14649	0.32	0.74
1.30 - 1.40	18.7	8.5	13822	0.96	1.50	65.0	4.6	14411	0.50	0.96
1.40 - 1.50	7.0	16.0	12080	1.57	2.22	72.0	5.7	14184	0.61	1.08
1.50 - 1.60	3.9	28.1	10840	3.10	3.65	75.9	6.5	14012	0.74	1.21
1.60 - 1.80	3.5	35.1	7977	3.76	4.10	79.4	7.8	13746	0.87	1.34
Sink 1.80	20.6	74.2	3781	1.12	11.9	100.0	21.4	11680	3.00	3.51

"float-sink" fraction. The cumulative values show the properties of the "float" or clean coal under perfect separation conditions at various separation gravities. Cumulative sink results would represent the refuse from perfect separation.

In the example set of washability data, shown in Table 4-1, the properties of the cleaned coal in the 50.8 x 9.5 mm (2 x 3/8 in.) size fraction separated at 1.60 specific gravity are:

Ash content	9.5 percent
Heating value	31,992 J/g (13,766 Btu/lb)
Pyritic sulfur content	1.13 percent
Total sulfur content	1.67 percent

The resulting SO_2 emission factor would be 1,040 ng SO_2/J (2.42 lb $SO_2/10^6$ Btu), assuming that all of the sulfur in the coal is emitted as SO_2.

The washability results can be plotted in a number of ways to produce a set of curves which are characteristic of the coal (see Figure 4-1). The "specific gravity" (yield) curve shows the theoretical yield of washed product from the raw coal for any specific gravity of separation. For example, at a specific gravity of 1.4, the yield for the coarse fraction (2 in. x 3/8 in.) is only about 63 percent of the feed material, while at a 1.6 specific gravity, the yield is 74 percent. A yield curve is plotted directly from the cumulative weight percent float data and specific gravity of separation (column 7 versus column 1 in Table 4-1). The cumulative float pyritic sulfur curve indicates the theoretical percent of pyritic sulfur of any given yield of washed product (columns 10 versus 1 in Table 4-1). Similarly, other properties of the washed coal, such as "cumulative float ash" or "cumulative sink ash" can also be plotted from data given in Table 4-1.

Another important piece of washability information to the coal preparation engineer is the "± 0.10 specific gravity distribution" (also

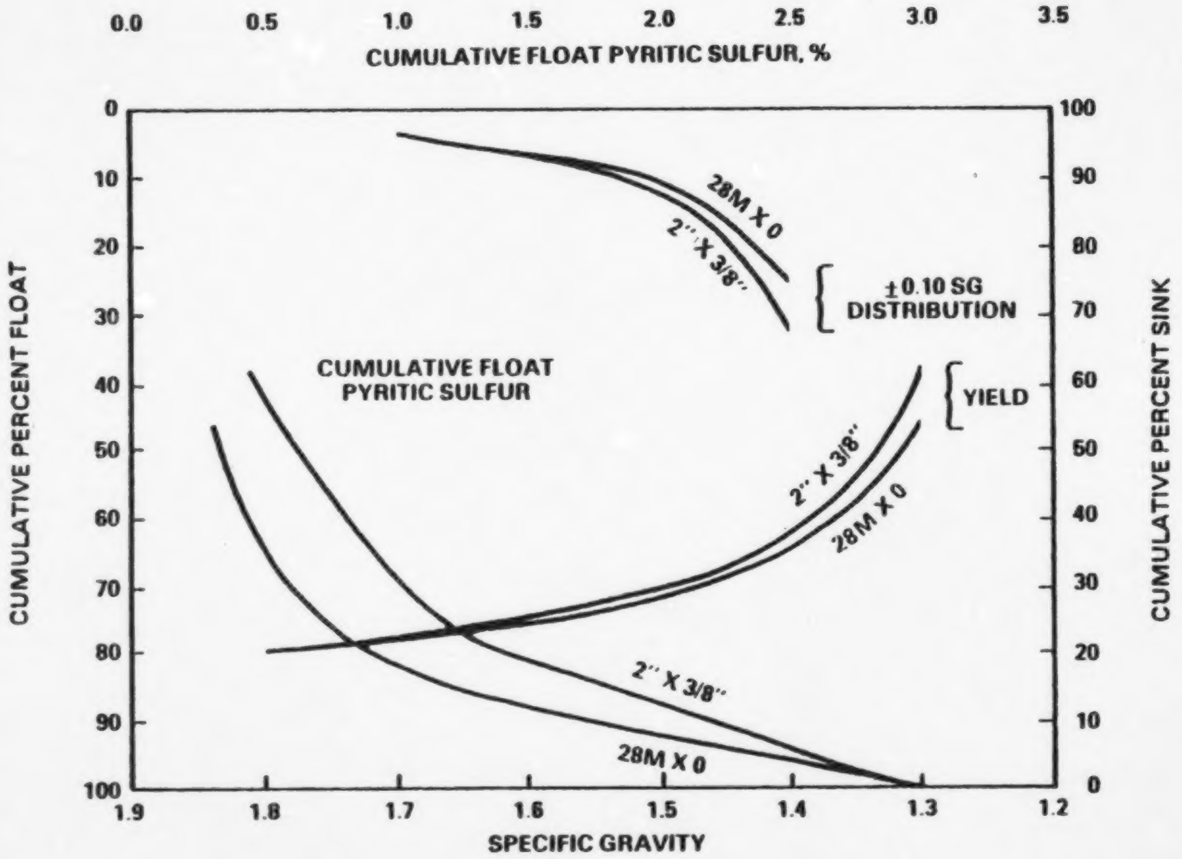


FIGURE 4-1 WASHABILITY CURVES, UPPER FREEPORT SEAM

referred to as "near gravity material"). The near gravity material shows the weight percentage of the coal that lies within + 0.10 and -0.10 specific gravity units at any specific gravity. It indicates the degree of difficulty of impurity separation in coal cleaning equipment.

For coal cleaning equipment using water as the separation medium, simple separation is expected if the near gravity material is less than 7 percent, and very difficult separation is expected if the near gravity material is above 15 percent. However, for heavy-media equipment, efficient operation at high values of near gravity material is also achievable. Figure 4-1 illustrates this performance characteristic. Assuming the design parameter for cleaning the coal is specified at 7 percent near gravity material, Figure 4-1 shows that: (1) the specific gravity of separation for both size fractions is 1.60; (2) the 50.8 x 9.5 mm (2 in. x 3/8 in.) size fraction will have a yield of 74 percent producing a cleaned coal containing 1.20 percent pyritic sulfur; and (3) the 0.6 mm x 0 (28 mesh x 0) size fraction will have a yield of 75 percent, producing a cleaned coal containing 0.75 percent pyritic sulfur.

From analysis of the washability data, various coal cleaning circuits are identified, and the operational parameters for each of these circuits are determined. This determination is dictated by the design objective and by a set of constraints. A typical design objective might be the minimization of coal cleaning costs. On the other hand, constraints can be dictated by product specifications, environmental regulations, or process requirements. Constraints dictated by specifications can be a maximum content of ash or sulfur or a minimum heating value in the product coal. Constraints specified by environmental regulations can be a maximum level for sulfur dioxide emissions from the cleaned coal. Constraints determined by process requirements can be a minimum value for energy recovery in the cleaned coal (e.g., minimum 90 percent Btu recovery).

After the operational parameters for each circuit are determined, various pieces of coal preparation equipment within each circuit are selected.

COAL PREPARATION EQUIPMENT

Coal preparation operations can be classified as comminution, sizing, cleaning, and dewatering. This section discusses the major types of coal preparation equipment used in today's coal preparation plants in the U.S. for each of these operations.

Comminution

The major objective of comminution in preparation plants is to reduce the run-of-mine (ROM) coal to sizes suitable for cleaning and to liberate mineral impurities. In addition, crushing is usually required to meet the product coal size specification dictated by the market. Production of fines in crushing is not desirable mainly because of the difficulty of cleaning, dewatering, and handling of fine size coal.

Crushing in a preparation plant is done in one or two stages, depending on the feed and product coal sizes, coal characteristics, type of crusher selected, and process economics. For efficient operation with hard coals (i.e., low grindability index) a reduction ratio (defined as the feed to product size ratio) of four is generally considered reasonable, and up to ten may be used. For friable coals, reduction ratios of as much as 40 may sometimes be economical.

Major types of crushers used in coal preparation plants today include rotary breakers, roll crushers, and hammermills. These are described in Appendix B, Section B.1

Sizing

Sizing of coal can be sized by air or hydraulic classifiers or by screens. Air classifiers, as their name implies, operate with air as a fluid and classify particles with sizes ranging from 5 to 150 microns.

Air classifiers do not operate efficiently if the feed material is wet and are not widely used for wet sizing of coal in preparation plants.

Hydraulic classifiers have a wider size range, with hydrocyclones classifying coal as coarse as 600 microns. The principle of operation of these devices is based upon the differences in particle specific gravities as well as sizes.

Screens in coal preparation are used for (1) separating refuse and fines prior to crushing, (2) separating raw coal into size fractions for further processing, (3) removing fines prior to cleaning; and (4) removing water. Screens accomplish a classification of particles on the basis of "size" alone, the acceptance or rejection of the particles being made by a screening surface. The separation mechanism and equipment descriptions are presented in Appendix B, Section B.2.

Cleaning

Cleaning is the step in which coal is separated from its impurities. The separation takes place in water, in a dense medium, or in air. Mechanisms for cleaning operations are based either on the specific gravity or on the surface property differences between coal and its impurities. Examples of coal cleaning equipment using water as the separation medium include jigs, concentrating tables, hydrocyclones, and froth flotation cells. Jigs are the most widely used coarse coal cleaning equipment in the U.S.

Dense-medium cleaning devices generally use a mixture of finely ground magnetite (minus 325 mesh) dispersed in water; they perform sharper separations than devices using water or air as the separation medium. Dense-medium devices currently used in the coal preparation plants include dense-medium vessels and dense-medium cyclones. Specific gravity of the medium in these devices can be adjusted by the amount of magnetite added and is normally set between 1.3 and 1.7.

The dry concentration method uses air as the medium. Use of this separation method reached a peak in 1965 in the U.S., but has decreased since then. The predominant pneumatic cleaner currently in use in the industry is the air jig. Descriptions of the various types of coal cleaning equipment are presented in Appendix B, Section B.3.

Dewatering

Cleaned coal and refuse streams from wet cleaning need dewatering to meet the product specifications and refuse landfill disposal requirements. Excessive moisture in the cleaned coal and refuse is undesirable because it creates handling problems and increases transportation costs. In addition, moisture reduces the heating value of the cleaned coal, increasing the boiler fuel requirement.

Selection of dewatering equipment for a certain application depends on the initial moisture content from the cleaning equipment, the desired level of moisture after dewatering and the size consist of the coal. Moisture can be removed by two types of devices: mechanical dewatering devices and thermal driers. Mechanical dewatering devices can be classified as those that do not produce a final product (e.g., cyclones and thickeners) and those that do produce a final product (e.g., screens, centrifuges, and filters). The performance of dewatering equipment is shown in Table 4-2 and described in Appendix B, Section B.4.

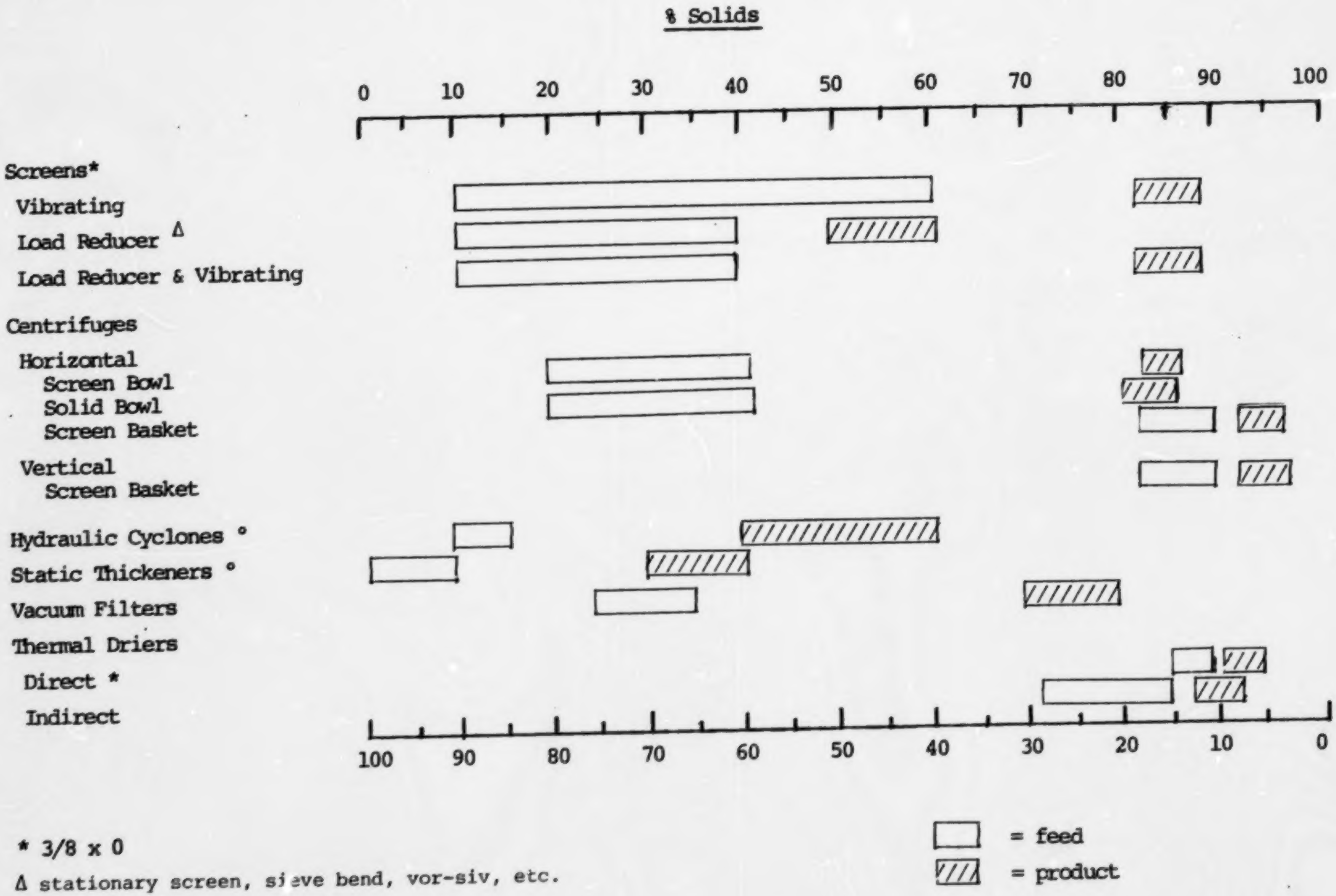
LEVELS OF COAL CLEANING

Different organizations vary in their definitions of coal cleaning levels. The example below is a commonly used alternative.

- No Cleaning (Level 1) - Steam coals are often used without cleaning. Currently, many coals are sold after only crushing and sizing to product specifications. Some mine debris and incombustible impurities are removed in the process.
- Partial Washing (Level 2: Coarse Cleaning Plant) - In a coarse-size plant, only the larger size fractions of coal are treated. Typically, a given coal could contain 50 to 60 percent plus 1.0 cm (+3/8-inch) coal with the fines reasonably low in ash and sulfur. The plus 1.0 cm portion of the feed is washed and

TABLE 4-2. FINE COAL DEWATERING AND HANDLING EQUIPMENT

Used on Coal 28M x 0 unless otherwise indicated



* 3/8 x 0

Δ stationary screen, sieve bend, vor-siv, etc.

° primary dewatering

mechanically dried to a low moisture content. The separated and untreated minus 1.0 cm (-3/8-inch) portion of the feed is combined with the cleaned coarse coal for shipment.

- Coarse Washing with Partial Washing of Fines (Level 3: Coarse-Size and Intermediate-Size Cleaning Plant) - In this case, all the feed is wetted, and coarse and medium size coal (typically plus 0.30 mm (48 mesh) fraction) is washed. All the washed coal would be mechanically dried. This approach normally results in the exclusion of the fine coal (minus 0.30 mm) material (the most difficult and expensive to dewater) from the product. This process generally results in a low yield and sometimes high cost.
- Total Washing (Level 4: All Size Ranges Cleaned) - In this case, all the feed is wetted and washed. Coarse, intermediate, and fine coal is cleaned in separate circuits. The washed coal fractions are combined into one product. A more complex plant (sometimes referred to as level 5) produces two or more products: deep cleaned coal and middlings coal.

PERFORMANCE PREDICTION OF COAL CLEANING OPERATIONS

Performance of coal cleaning operations can be estimated directly from the coal washability data. Using the washability data shown in Table 4-1, and assuming that the coarse, intermediate, and fine coal fractions are cleaned at respective specific gravities of 1.40, 1.50, and 1.60, properties of the product coal from each circuit and the total plant product can be estimated as shown in Table 4-3.

Unfortunately, washability data predict cleaned coal of better quality than actual plant operations produce. This is because of the imperfect operation of coal preparation equipment. For example, cleaned coal from a cleaning device will contain some particles that the washability data, are predict will report to the refuse stream; also, the oversize from a screen will contain some fine particles that would be expected to report to the undersize stream.

TABLE 4-3: Product Coal Properties Derived from Washability Data

Btu)	% Weight Yield	Heating Value (Btu/lb)	% Total Sulfur	% Btu Recov.	SO_2 Emission $ngSO_2/J$ (ng SO_2/J	lb $SO_2/10^6$
Coarse Coal Circuit Product (2"x3/8")	62.4	14,810	1.40	79.8	813	(1.89)
Intermediate Coal Circuit Product (3/8"x28 mesh)	70.5	14,005	1.13	86.5	692	(1.61)
Fine Coal Circuit Product (28 mesh x 0)	75.9	14,012	1.21	91.1	744	(1.73)
TOTAL PLANT PRODUCT (2"x0)	68.9	14,225	1.22	85.2	735	(1.71)
Raw Coal (No Washing)	100	11,504	3.40	100	2,273	(5.29)

A better prediction of coal cleaning operations can be made by taking into consideration the imperfect operation of coal preparation equipment and using the fine coal washability data. The split of the feed material into various streams in coal preparation equipment can be predicted from the performance information of that equipment. For coal cleaning equipment, this information is called the distribution or performance curve. It is a plot of percent distribution of the raw coal to the cleaned coal product versus the specific gravity of the raw coal slurry. It indicates the percentage of material in the feed, with a certain specific gravity, that will be distributed to the cleaned coal product. The performance information of coal preparation can be obtained from equipment manufacturers' data or coal cleaning literature. Figure 4-2 shows examples of distribution curves for various coal cleaning equipment.

It is common to use parameters instead of the whole distribution curve for describing the operation and efficiency of a cleaning equipment. The specific gravity of separation, d_{50}, is the specific gravity fraction at which the feed is partitioned into equal fractions of refuse and cleaned coal (see Figure 4-3); this is the specific gravity that corresponds to the midpoint (50 percent point) of the ordinate of the distribution curve. A coal cleaning device can be adjusted physically so that the value of d_{50} can be decreased or increased. The probable error is a very common criterion used for measuring the efficiency of a cleaning device. It is one-half of the difference between gravities corresponding to 25 and 75 weight percent recoveries. Generally, the steeper the distribution curve, the smaller the probable error, and the sharper the separation of the cleaned coal from its impurities. Another efficiency measure for coal cleaning equipment is the error area (shaded portion in Figure 4-3). It is defined as the total area lying between the perfect separation (vertical) line and the distribution curve. The smaller this area, the greater the efficiency of the coal cleaning equipment.

As can be seen from Figure 4-2, dense-medium vessels and cyclones operate more efficiently than equipment using water or air as the separation medium. The efficiency of coal cleaning equipment is also affected by the feed size distribution. For a given piece of coal cleaning equipment, the efficiency of cleaning decreases with smaller particles.

For the above-described reasons, the performance prediction of coal cleaning operations depends not only on the properties of the feed coal, but also on the type of equipment used and the operating parameters selected. Computer simulation models have been developed to predict the performance of coal preparation operations and to estimate the properties of the product coal. For existing coal preparation plants, these performance prediction results may be compared with and validated against actual plant data that can be generated from sampling of feed, product, and refuse streams. The accuracy of the simulation model depends upon

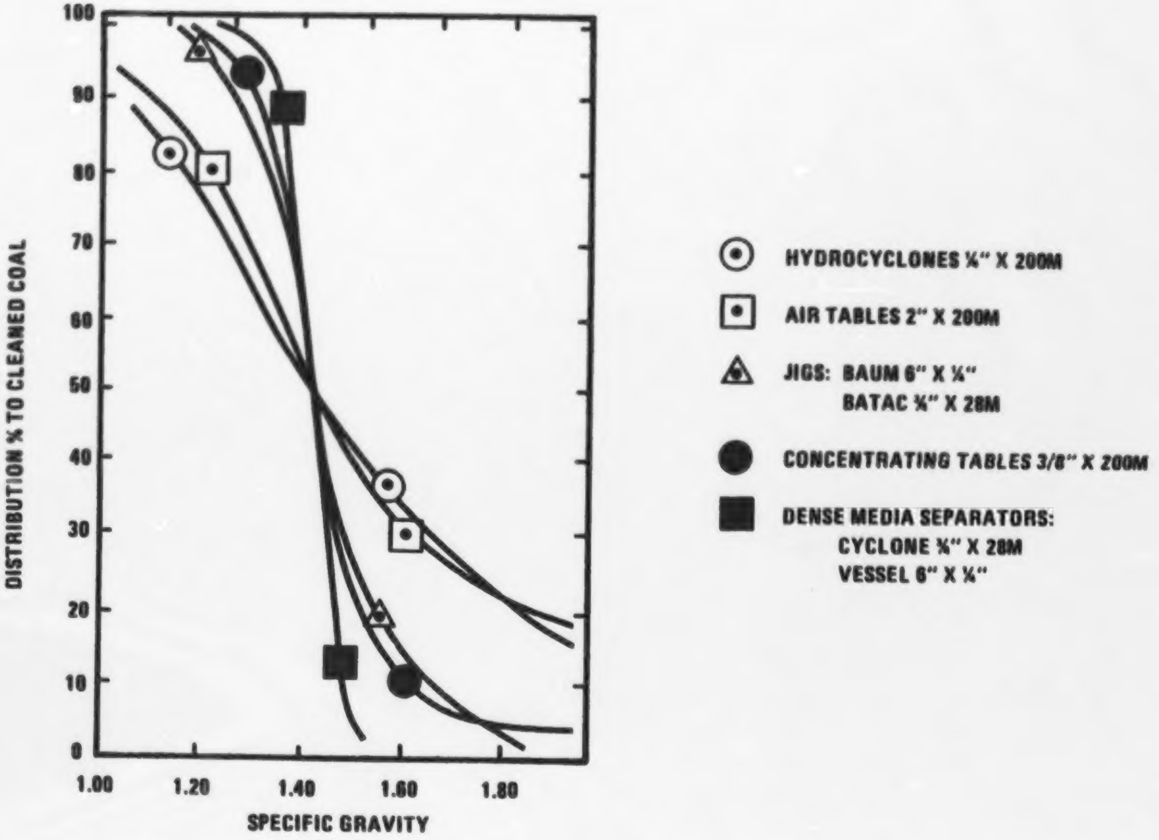


FIGURE 4-2 DISTRIBUTION CURVES FOR SELECTED COAL CLEANING EQUIPMENT

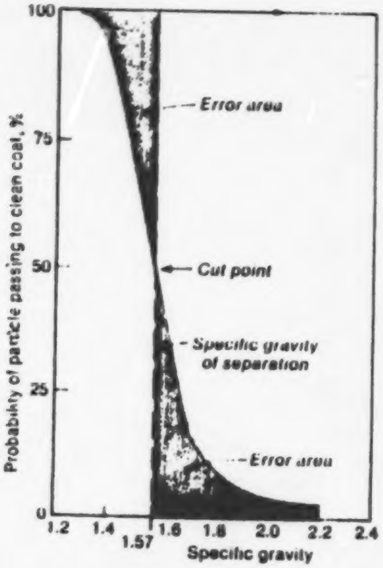


Figure 4-3. Specific gravity of separation and error area.

coal type, circuit design, and the similarity of performance curves in the model to actual equipment performance. Overall, computer simulation models have proved to be good tools in designing plants, predicting general cleaning performance, and determining whether further plant improvements can be obtained.

IMPACT OF COAL MINING TECHNOLOGIES

For a given coal, the type of mining (strip, conventional, or continuous) affects the amount of dilution material (i.e., overburden, roof, bench, and/or floor of a mine) in the raw coal. The amount and characteristic of the dilution material is a function of its geologic formation. Strip mining is a surface mining method which removes the overburden that covers the coal seam in a series of parallel strips. The amount of dilution material associated with strip mining is relatively small. In the Western Coal Region, there is essentially no dilution material while in the Eastern coal regions, the amount typically averages 3 to 5 percent for non-washed coals. Conventional mining in underground or deep mines involves a selective, hand loading process. Continuous mining is a mechanized technique. One large coal company has found that continuous mining produces 3 to 5 percent more dilution material than conventional mining techniques. The tradeoff for this additional dilution material is increased mine productivity. The dilution material is removed by coal cleaning. For example, one company increased its mine productivity 30 percent after adding continuous miners and building a coal preparation plant. The coal preparation plant eliminated the requirement of more selective mining techniques.

The mining technique also significantly affects the size characteristic and the ash content of the raw product. Coal cleaning plant equipment and circuits are designed for a specific size distribution feed of the raw coal and the amount of non-combustibles that can be liberated during cleaning.

The percentage of minus 1/4 inch material and the percentage of minus 28 mesh material associated with raw coal is larger for a product recovered via continuous miner than for either conventional or surface mining. Experience of a large mining company indicates the following:

	Weight of Material	
Mining Method	Less Than -1/4 Inch Material	-28 Mesh
Strip	15%	2-4%
Conventional	25%	8%
Continuous	40%	18%

Continuous miners also cause about 15 percent more of the raw coal feed to be processed by fine coal circuits, compared to coal mined by other conventional methods. Fine circuits are generally more expensive than coarse circuits per ton of input capacity. As a result, the larger feed percentages of fine material and ash associated with continuous miners affect washing performance, as follows:

- The complexity and cost of an appropriately-designed cleaning plant increases substantially.
- Both the mined and cleaned coal retain more moisture (e.g., from rain, barge sprays, etc.).
- Operating costs increase because of:
    1. Conveyor plugging difficulties.
    2. Reduction in pulverizer capacity.
    3. Transport unloading difficulties (e.g., plugging and freeze-ups).
    4. general operational handling difficulties.

In addition, as bituminous coal absorbs moisture (greater potential with decreasing particle size), an exothermic reaction occurs and spontaneous combustion can result.

BLENDING

Two or more coals can be blended as an alternative to, or in conjunction with, coal washing. Normally, a coal with a sulfur content that exceeds a given sulfur dioxide emission standard is blended with a lower sulfur compliance coal. Blending permits an increase in the amount of compliance coal and can make coals marketable that would otherwise not be. For very high sulfur coals, coarse washing followed by blending may be the preferred option to make the coal more marketable. The technique is most applicable for SIP standards between 560 and 2150 ng SO_2J (2.0 and 5.0 lb $SO_2/10^6$ Btu).(1)

To determine the resultant coal emission potential from blending Coal A with Coal B, one can use the following equation:

$$E = \frac{(S_A W_A + S_B W_B)}{H_A W_A + H_B W_B} (20 \times 10^6)$$

where:

E = Emission of blended coal (ng/J)

S = Sulfur content percentage of the coal

W = Weight percent of each coal (in decimal)

H = Heating Value of the coal (KJ/Kg)

and subscripts represent each coal blended.

Given an emission limit, one can solve for the blending weight percentages (note that $W_A + W_B = 1$) for only two coals being blended. Blending costs are typically between \$2 and \$2.50 per ton of blended coal (January 1982 basis).(2)

REFERENCES SECTION 4

1. Coal Preparation Industry Study, Draft. U. S. Environmental Protection Agency. Office of Air Programs, Industrial Studies Branch. December 14, 1971.
2. Coal in America: An Encyclopedia of Reserves, Production, and Use. Richard A. Schmidt, Ed. Coal Week. McGraw-Hill Publications Company. 1979.

SECTION 5.0

POLLUTION CONTROL AND WASTE DISPOSAL TECHNOLOGIES

Numerous factors influence the amount and form of pollutants emitted from coal cleaning facilities to the surrounding environment. Among these factors are: type of coal, mining methods, siting and geographical location, cleaning process, and level of preparation. Even though some generalizations concerning the effect of each of the above factors on pollution are possible, all of these factors must be considered simultaneously when drawing conclusions about environmental impacts from individual preparation plants.

Some pollution control technologies are currently being applied to coal cleaning facilities. The extent to which a technology is applied depends on the specific regulatory requirements applicable in a particular region or state.

Air Emissions

Control of air pollution from coal preparation plants is mandated by regulations set under the authority of the Clean Air Act of 1977. Section 111 of the Act mandates the setting of New Source Performance Standards (NSPS) for new stationary sources which may emit air pollutants. Standards of performance currently apply to coal preparation plants processing more than 200 tons of coal per day. The specific processes affected by NSPS are thermal dryers, pneumatic coal cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading facilities. Coal storage and transfer operations are governed by NSPS only if they form a part of the coal preparation facility; isolated coal storage and transfer stations are excluded.

The results of an EPA 1972-74 study that sampled and analyzed off-gases from scrubbers associated with thermal dryers found that gaseous pollutant emissions, containing SO_x, NO_x, CO, hydrocarbons, and trace elements (and in some cases radioactive compounds), would not significantly degrade ambient air quality.(1)

The NSPS for coal preparation plants only address particulate matter. The standards are as follows:

- Thermal dryer - Exhaust gases discharged to the atmosphere shall not contain particulate matter in excess of 0.070 g/dscm, and shall not exhibit 20 percent or greater opacity.
- Pneumatic coal cleaning equipment - The gases emitted to the atmosphere shall not contain particulate matter in excess of 0.040 g/dscm, and shall not exhibit 10 percent or greater opacity.
- Other facilities - Gases emitted into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading facility shall not exhibit 20 percent or greater opacity.

Under this program for EPA compared control levels specified by the states for existing plants with the current NSPS standards for coal preparation plants. It found that state standards for existing preparation plants are generally less stringent than the Federal NSPS. Of the 25 coal producing states surveyed, 7 states have adopted specific regulations for coal preparation plants. Other states regulate coal preparation plants by general process emission regulations.

Fugitive Dust--

Dust concentrations vary depending on the type of operation, the size and moisture content of the coal at each point of operation and the rank of coal. Dust generation is usually produced during the following unit operations:

- Coal Storage - from coal storage piles and from silos and bins during loading and unloading.

- Transport - from belt conveyors, various types of vehicles, or bucket elevators.
- Materials Handling - when loading and unloading conveyors or transferring coal among the processing steps.
- Crushing and Screening.

Coal storage--Few options are available for controlling particulate emissions generated by the live storage pile. The continuous addition and withdrawal of coal from the piles reduces the effectiveness of water or chemical sprays. Windscreens are only marginally effective in reducing the emissions. One method that effectively controls emissions is the use of a totally enclosed storage area, such as silos.(2) This method provides essentially complete control of fugitive dust, with emission reductions from live storage normally in the 95 to 99 percent range. The cost of using enclosed storage (about $125 per ton of storage) cannot be totally attributed to the need for particulate control, since there are other significant benefits associated with the use of enclosed storage. These benefits include: protection from rain and snow, reduced freezing of coal, aesthetics, and prevention of coal loss.

Two methods are available for controlling particulate emissions generated by wind erosion at relatively inactive storage piles. These are the use of water sprays or of chemical binders. Both water and chemical sprays reduce particulate emissions by wetting the material which causes the particulates to cling to each other and to larger particles. Watering is estimated to cost $2 to $5 per acre per day, while chemical stabilization is estimated to cost $25 to $50 per acre per application.(3) These higher costs in chemical spray systems are due to continuous requirements for chemicals, storage facilities, mixing equipment, and increased treatment of the runoff.

Transfer points--Loading and unloading conveyors and process equipment are major dust-generating steps. Transfers from conveyor to conveyor or from conveyors to screens and crushers may be equipped with hoods or sprays with minimal open areas. For hoods, particle-laden air may be exhausted to a central dust collection system. Fabric filter collectors are considered the most suitable dust control device for the central dust collection system.(3) Dust trapped in the fabric filter collectors is periodically emptied from the baghouses and recycled to the coal stream. Dry cyclones used in the past as pre-cleaners for the collection of the larger particles are, in general, no longer necessary.

Crushing/screening--Equipment associated with crushing/screening are normally enclosed and hooded, with a minimum of open area, and the particle-laden air is exhausted to the central dust collection systems.

Thermal dryer emissions--Emissions from thermal dryers include particulates from the coal bed being dried and particulates in the form of fly ash from the coal-fired furnace that supplies the drying gases. Particulate concentration and size vary widely from one dryer to the next depending on the feedstock and differences in drying operations. Stack emissions of fine and ultrafine particulates from thermal dryers can be adequately controlled by using cyclones followed by wet scrubbers.

Water Pollution Control

The primary mandate for protecting the waters of the United States is the Federal Water Pollution Control Act (commonly referred to as the Clean Water Act (CWA)). The final regulations for coal preparation plants as printed in the October 13, 1982 Federal Register establish NSPS for coal preparation plants at zero discharge of pollutants. However, occasional purges will be allowed to reduce the concentration of solids and/or process chemicals in the water circuit to a level which will not interfere with the preparation process. To use the purge allowance, the plant operator must submit a written notice in advance to the permitting authority. The zero discharge requirement was promulgated for coal preparation plants because EPA feels it is a demonstrated technology in this subcategory. Many existing plants are currently practicing total recycle of preparation plant wastewaters. Further, EPA feels this option is feasible for new sources at a reasonable cost, since wastewater treatment and management practices can be planned at the design stage, thereby avoiding costly retrofit. Finally, total recycle will remove considerable amounts of conventional pollutants, such as total suspended solids (TSS).(4)

EPA is deleting the design criteria for sedimentation ponds. It will no longer be required that a pond be sized to contain the runoff from the 10-year, 24-hour storm event. Instead, limitations for settleable solids of 0.5 ml/l and pH limitations of 6-9, will apply during precipitation events less than or equal to the 10-year, 24-hour storm event. During dry weather flows, total iron and total manganese have been selected for control. The effluent limitations for existing and new sources are shown below:

Source	Parameter	Maximum for Any Day (mg/l)	30-Day Average (mg/l)
Existing	Total Iron	7.0	3.5
	Total Manganese	4.0	2.0
	TSS	70	35
	pH	6.0-9.0	6.0-9.0
New	Total Iron	6.0	3.0
	Total Manganese	4.0	2.0
	TSS	70	35
	pH	6.0-9.0	6.0-9.0

The National Coal Association (NCA) filed suit against EPA, primarily because NCA felt there should be geology-and topography-based exceptions to the zero discharge requirement for new sources.(5) For example, plants located in areas where the ground water table is close to the surface, can not use sedimentation ponds for wastewater treatment. NCA maintained that such plants should be allowed to meet the effluent limitations and discharge to surface waters. On August 1, 1983, EPA entered into a settlement agreement with the Commonwealth of Pennsylvania, the National Coal Association and the West Virginia Mountain Stream Monitors which resolves all challenges raised with respect to the effluent limitations guidelines and standards promulgated under the Clean Water Act for the coal mining point source category (47 Fed. Reg. 45382, October 13, 1982). As part of the settlement agreement, EPA has agreed to propose revised NSPS for coal preparation plants. These proposed standards would allow a discharge of pollutants with limitations on iron, manganese, suspended solids and pH. Thus, eliminating the zero discharge with a purge allowance. NCA contended that coal slurry ponds, which are a part of the preparation plant water circuit, are not always able to achieve zero discharge. In addition, coal waste impoundments, including some slurry ponds, must meet OSM requirements to drain water from the pond during precipitation events.

For existing facilities that treat their wastewaters prior to discharge, the wastewater treatment methods include settling ponds, thickeners and filters, or combinations of these methods. With the help of chemical agents, total suspended solids (TSS) and iron and manganese can be reduced to concentration levels meeting current effluent regulations.(6)

Runoff water from associated areas is controlled by: preventing precipitation from coming into contact with coal storage and refuse piles and associated areas by enclosing the piles; and constructing ditches and subdrains around these sources to direct the runoff water to the water treatment system. Treated runoff water is either recycled or discharged.

Settling ponds--Settling is the separation of suspended particles from water by gravity. Settling (or sedimentation) ponds are large earthen impoundments often from 100,000 to 300,000 cubic meters (30 to 80 million gallons) in capacity. Pond size is determined more by the solids storage capacity than by the efficacy of suspended solids removal except as needed to meet the TSS effluent limitations. Retention times provided vary from as little as one day to as much as several months.

Many plants, particularly in mountainous areas, use several small ponds. These ponds may be constructed in a series, with the supernatant liquid of one flowing into the next so that each pond produces a progressively lower solids concentration than the previous one. Some preparation plants use two ponds for slurry treatment. When one pond has reached capacity, the slurry is sent to the second pond and the first pond is dredged. After the second pond fills, flow is returned to the first and the cycle is repeated.

Preparation plants in regions with high clay content may encounter problems with high levels of colloidal material in the process water. In such cases chemical flocculants are added to facilitate settling.

Ponding costs vary with the size and location of the pond, area geology, and the type of the terrain. Typical annual costs (1977 dollars) range from 25 to 85¢/cu m of water treated in the pond, including the annualized capital investment and the flocculant costs. EPA has estimated that for new sources, where zero discharge is required, additional ponding capital costs may be as high as $1.6 million and incremental annualized costs may reach $379,000 per year (1982 Dollars).(6)

Clarifiers/thickeners--Preparation plants produce a fine refuse slurry that is difficult to handle. Large quantities of minus 0.07 millimeter (-200 mesh) solids consisting of clays, and shales in a colloidal and semi-colloidal suspension compound this problem.

Thickeners (or clarifiers) are used to separate fine tailings from spent circuit water. The use of a flocculant is generally necessary to enhance separation efficiency. The percent solids in the feed seldom exceeds 15 percent and is more normally 2-5 percent. The concentrated slurry (underflow) can have a solids concentration of up to 60 percent. The clarified effluent (overflow) is recycled back to the plant.

Typical thickeners used in coal preparation plants can handle 0.5 gpm water/ft^2 of thickener surface area. The capital investment cost of such thickeners is about \$6,560/m (\$2,000/ft) diameter (1979 dollars).

Vacuum filters and filter presses--Disc and drum filters are used in the coal industry to dewater suspensions of fine material. The multiple disc filter is the most widely used. This device consists of several filter discs up to 15 ft. in diameter mounted on a slowly revolving horizontal shaft.

While submerged, in the slurry, a vacuum is applied to each disc, causing the coal or refuse to form a cake on the filter medium.(7) As the discs rotate, the adhering material is lifted out of the slurry and a positive pressure is applied to each disc, causing the filter cake to discharge into a receiver. Scrapers are also used to dislodge the cake. Drum filters work on the same principle as the discs, but the vacuum is applied to horizontal rather than vertical surfaces.

Filter presses are new to the coal industry, and can achieve higher moisture removal efficiencies than disc filters. However, they are only economical where high dewatering efficiencies are essential to coal quality.(8) In filter presses, sludge is pumped between pairs of filter plates, forcing water out through walls of the plates. The plates are then separated to remove the dewatered product.

Solid Waste Control

Control of solid wastes from coal mining is regulated by the Office of Surface Mining (OSM) of the Department of Interior. The Surface Mining Control and Reclamation Act (SMCRA) defines guidelines and procedures for the disposal of solid waste. However, the EPA Mandate from the Resource Conservation and Recovery Act (RCRA) must be considered by OSM. RCRA, as amended in 1978 and 1980, provides overall statutory authority for control of solid wastes in the U.S.

Pursuant to the 1980 Amendments to RCRA, a study was conducted to determine the hazard classification of mining wastes.(9) Coal wastes were classified as non-hazardous, and control over coal wastes was delegated to the Department of the Interior. Present controls for solid wastes from coal cleaning are found in SMCRA regulations. These relate mostly to stability, burning, and pollutants leached from the waste and discharged to water. Control technologies are mainly construction and operating standards that are designed to prevent environmental degradation.

Disposal Methods--

There are four classes of methods that have been investigated, or are being used, for the disposal of preparation plant refuse. These are:

- Surface disposal.
- Underground disposal.
- Refuse utilization.
- Resource recovery.

The suitability of a method depends on the chemical and physical properties of the refuse, the type of mining employed, and the topography surrounding the preparation plant.

Surface disposal--Surface techniques are by far the most prevalent methods for disposing of preparation plant refuse in the United States. The total cost of refuse disposal is greatly affected by transportation costs. The nearest suitable location is typically chosen as the disposal site, and it is often onsite. In hilly or mountainous terrain, common in the Appalachian region, coarse refuse is deposited in valleys or on the side of a ridge. In the Midwest where the flat terrain precludes the use of any other configuration, the refuse is simply deposited in piles.

Subsequent to dewatering (described in the previous section) fine refuse is disposed of in the coarse refuse pile, blended with the coarse refuse prior to disposal, or solidified chemically and allowed to remain where the solidification took place.

Regulations mandated by the Office of Surface Mining (Department of Interior) reduce the pollutant production associated with refuse disposal. The following OSM requirements affect the amount and nature of pollutants that are produced at a refuse disposal site:(9)

- Covered subdrains must be used to prevent surface waters from coming in direct contact with the refuse.
- Refuse must be spread in lifts no greater than 24-inches thick and compacted to attain 90 percent of the maximum dry density.
- Before a refuse pile is closed, it must be graded, covered with 3 feet of the best available non-toxic, non-combustible material, and revegetated as quickly as possible. Less than 3 feet of cover may be used if it is shown that the revegetation requirements can still be met.
- If refuse is to be used in the construction of a dam or impoundment, it must be demonstrated that seepage through the impoundment will not have a deleterious effect on downstream water quality.

Cost estimates for the surface disposal of refuse were made by Brown in 1977.(10) These estimates were based on a preparation plant that produces 2.44 million metric tons (2.69 million tons) per year of product coal, 0.962 million metric tons (1,060,000 tons) per year of coarse refuse, and 100,000 metric tons (110,000 tons) per year of fines. Three different disposal systems were considered:

- Mechanical fines dewatering, blending of fines and coarse refuse at the preparation plant, transportation of mixture to disposal site for co-disposal.

- Pumping fines slurry to impoundment created using coarse refuse.
- Pumping slurry to settling ponds, excavating the material once it settles, disposal in pits with the coarse refuse.

The estimated costs for the three systems were, respectively, $0.82, 0.74, and 0.90 per metric ton, and $0.74, 0.67, and 0.82 per ton, of cleaned coal.

Alternative methods for reducing pollutant levels in refuse pile drainage were investigated at the Los Alamos Scientific Laboratories (LASL). These methods included disposing of the refuse with neutralizing agents, disposing of the refuse with materials that have a high capacity for adsorbing trace elements, and using watertight sealants on the refuse pile.(11)

Materials that have been investigated as potential neutralizing agents and added to refuse prior to disposal include crushed limestone powdered lime and fly ash. Experiments performed by LASL indicate that codisposal of refuse with alkaline neutralizing agents can be effective for preventing the production of contaminated drainage. The primary technical problem associated with the method is matching the neutralization rate with the acidity production rate over the long term.

LASL has made some preliminary cost estimates for some of the promising techniques, as shown below. Costs are adjusted to March 1978 and vary depending on treatment parameters and refuse properties.

Technique	Cost ($/metric ton of coal)	Cost ($/ton of of coal)
Calcining	2.36 - 5.45	(2.14 - 4.94)
Lime Co-disposal	0.71 - 2.26	(0.64 - 2.05)
Flyash Co-disposal	0.43 - 6.56	(0.39 - 5.95)
Limestone/Flyash Co-disposal	0.28 - 4.38	(0.25 - 3.97)
Local Soils Co-disposal	0.89 - 1.43	(0.81 - 1.30)

Surface disposal of preparation plant refuse is, and will continue to be, the predominant method for disposing of this waste. Dewatering of fine refuse and disposing of it with the coarse refuse appears, in many instances, to be an attractive alternative to the use of slurry ponds for closing a plant's water circuit. Cheaper, more effective means for producing a dewatered material would further improve the feasibility of this option.

Underground disposal--One alternative to surface disposal of coal preparation refuse is underground disposal in the cavity left by the mining operation. Underground disposal eliminates the surface water pollution problems associated with surface disposal methods and also, to a limited extent, can reduce the surface subsidence that is commonly associated with underground mining. There are basically two systems used to place refuse underground: hydraulic flushing and pneumatic stowage. Variations on each of these techniques, depend on the type and placement of equipment in use and mining methods. Underground disposal is used in Europe, but is not practiced in the United States, primarily because:(12,13)

- Both pneumatic and hydraulic disposal techniques were developed for use with longwall mining equipment, and not with room and pillar techniques prevalent in the United States.
- The use of blind hydraulic flushing requires the presence of an abandoned underground mine in close proximity to the preparation plant.
- Underground disposal, other than blind flushing, requires the presence of additional workers underground, which increases the number of persons exposed to a hazardous working environment.
- Underground stowage is a time-consuming operation that cannot keep pace with rapidly advancing longwall equipment and thus is not feasible where mining is done on a 24-hour per day basis.
- The costs of surface disposal are considerably lower than those for underground disposal.

Underground disposal costs were estimated by the National Academy of Sciences in 1975.(14) The resultant costs were \$1.30 per metric ton (\$1.18 per ton) of product coal for pneumatic stowing and \$1.57 per metric ton (\$1.43 per ton) for hydraulic backfilling.

Refuse utilization--Another alternative to surface disposal is to use the refuse directly, or after some form of treatment, as a structural or fill material. The physical properties of refuse are comparable to those of other common fill materials such as earth or sandstone. After appropriate treatment, refuse can be used as an aggregate for manufacture of lightweight concrete.

Coarse refuse has been used as a fill material in the construction of highway embankments. In the United States, this has generally been done on an experimental or "demonstration project" basis, except in Pennsylvania, where the presence of numerous old refuse piles with their attendant pollution and aesthetic problems has provided an added impetus to the use of this material. The Cross-Valley Expressway near Wilkes-Barre, the Monongahela Valley Expressway, and the Lackawanna Valley Expressway were three Pennsylvania projects that used, respectively, 1.15 million, 3.06 million, and 2.29 million cubic meters (1.5 million, 4 million, and 3 million cubic yards) of old refuse as fill. In addition, the EPA tested coarse refuse, both alone and mixed with lime and fly ash, as parking lot and road base material. The conclusions were that coarse refuse alone was not suitable because its high permeability would produce polluted leachate. The refuse/fly ash blends, however, would be acceptable because the fly ash reduces the permeability of the base and also tends to neutralize the acidity-producing potential.(15)

In instances where refuse has proven to be technically suitable for use in a particular application, one or more of the following has prevented widespread application:.(15)

- Refuse is competing against an inexpensive, readily available material such as shale, slate, or gravel. The additional distances that refuse must be transported make it an uneconomical choice.
- Projects such as road embankments require large amounts of material over a relatively short time span. The required quantities frequently exceed those normally produced by preparation plants.
- The pollution potential of the refuse requires consideration. In use as an embankment or fill material, the refuse must be adequately sealed to prevent the production of contaminated leachate. When refuse is used in the production of lightweight aggregate, the generation of leachate may be a problem.

Resource recovery--Coal refuse contains most of the elements that are currently mined and recovered commercially. With a few exceptions, the concentrations of most elements are not significantly higher than the corresponding concentrations of these elements in the earth's crust. In addition, those elements that do show elevated concentrations relative to their average concentrations in the earth's crust do not have concentrations as high as those found in commercially valuable ores. The only advantage coal refuse has over such ores is that mining is not required before resource recovery can commence. However, none of the recovery processes developed appears to be economical at the present time.

SUMMARY OF ENVIRONMENTAL ASSESSMENT RESULTS

This section summarizes the results and conclusions of two Source Test and Evaluation Programs conducted for the EPA at coal preparation facilities(16). The major objective of the test programs was to perform a screening (i.e., Level 1) Environmental Assessment on the discharge streams and fugitive emissions of the facilities, determine which discharge streams or emissions may be important for further characterization, and evaluate the effectiveness of pollution control systems.

Methods for Characterizing Waste Streams

Three methods were used to evaluate the characteristics of the coal preparation plant samples:

- Comparison of inorganic constituent concentrations with Discharge Multimedia Environmental Goals (DMEGs).

- Water quality parameter comparisons with existing standards.

- Bioassay screening tests.

The following streams were selected for study based on their potential for pollution and accessibility:

- Fugitive particulates and gases (non-point source) from coal and coarse refuse storage areas.

- Fine refuse slurry sedimentation ponds, and runoff ponds.

- Runoff from coal and coarse refuse storage areas.

- Coarse refuse.

- Fine refuse slurry.

Assessment method--Comparisons of the inorganic constituent concentrations with DMEGs were made to suggest which individual constituents and waste streams should be given further attention. The ratio of the concentration of an individual constituent to its DMEG value is denoted in the table as "discharge severity" (DS). The sum of the individual discharge severities is denoted as the "total discharge severity" (TDS). If the value of DS or TDS is found to be greater than one, then it is deemed that the constituent or stream deserves further characterization and monitoring attention.

Water quality comparisons--Water quality tests were performed on the runoff and filtrate samples. The test concentrations were compared to the most stringent state effluent water regulations for eastern and midwestern states. The applicable water quality test concentrations for runoff and leachate samples were also compared to the Resource Conservation and Recovery Act (RCRA) Extraction Procedure-Toxicity Concentrations for determining hazardous wastes, although a neutral leachant procedure was used.

Bioassay screening tests--Biological test result evaluations are based on an interpretation of the data in terms of low, moderate, or high effects for each test. "Low or nondetectable effects" mean that the material will not have any adverse health or ecological effects. "Moderate" or "high effects" mean that the material may be potentially hazardous and more rigorous testing should be initiated.

Coal Preparation Plant No. 1 Description

The coal cleaning plant chosen for the first assessment is representative of a group of cleaning plants that process ROM coal (Kentucky No. 9 and No. 11) with low pyritic (<2 percent) content, use only coarse cleaning technology (i.e., jig plant), and operate in an environment with high rainfall (>60 cm/yr) and a low soil neutralization potential (pH <6.0). The facility is a 450 Mg/h (500 t/h) coal washing plant. Its yield is about 55 to 60 percent.

Coal Preparation Plant No. 2 Description

The coal cleaning plant chosen for the second assessment is representative of a group of cleaning plants that processes ROM coal with high pyritic sulfur (>2 percent) content, uses high technology coal cleaning processes (i.e., fine coal cleaning), operates in an environment with high rainfall (>60 cm/yr), and has a low soil neutralization potential (pH <6.0). Preparation plant No. 2 is a 1,088 Mg/h (1,200 tph) coal washing plant. Its yield is approximately 74 to 76 percent.

Summary of Environmental Assessment

A summary of the multimedia chemical and biological stream characteristics and control strategy recommendations for Coal Preparation Plant No. 1 and Coal Preparation Plant No. 2 are provided in Table 5-1 and Table 5-2, respectively.

Fugitive Emissions--

Based upon the results from Plant No. 1, and No. 2, there does not appear to be a fugitive dust problem at the plant boundaries. The results did not support the need for further study of fugitive air emissions.

Liquid Waste Streams--

Aluminum, cadmium, nickel, and silver had concentration ratios which warrant further analyses, in most liquid streams from Plant No. 1. Manganese and nickel in most liquid streams from Plant No. 2 are candidates for further monitoring. The presence of these metals in liquid waste streams is not unexpected since they are found in the coal. They are not produced by the preparation process. These results support the need for further characterization and pollution control of liquid streams.

TABLE 5-1. SUMMARY OF ENVIRONMENTAL RESULTS - PREPARATION PLANT NO. 1

Waste Stream	Total Discharge Severity		Major Contributors (Discharge Severity >10)		Biological Results		Conclusions	Recommendations
	Health	Ecological	Health	Ecological	Health	Ecological		
Clean Coal Fugitive Particulates	5E-3	9E-3	-	-	L.N.	N.C.	• Low potential for hazard according to TDS values and bioassay test results. • High downwind TSP values for particulates. • Particulate morphology shows mostly dust, not coal, in downwind samples.	• Improve dust control/ suppression techniques.
Coarse Refuse Fugitive Particulates	3E-3	1E-3	-	-	L.N.	N.C.		
ROM Fugitive Particulates	1E-2	1E-2	-	-	L.N.	N.C.		
Upwind Fugitive Particulates	4E-3	3E-3	-	-	L.N.	N.C.		
Downwind Fugitive Particulates	3E-3	2E-3	-	-	L.N.	N.C.		
Clean Coal Storage Pile Vapors	3E0	2E-1	-	-	L.N.	N.C.	• Low potential for hazard according to TDS values and bioassay test results.	
Coarse Refuse Pile Vapors	1E1	3E-1	-	-	L.N.	N.C.		
ROM Storage Pile Vapors	4E0	2E-1	-	-	L.N.	N.C.		
Upwind Vapors	3E0	3E-1	-	-	L.N.	N.C.		
Downwind Vapors	6E1	2E0	Cr	-	L.N.	N.C.		

N.C. = Not conducted
L/N = Low or nondetectable effect
M = Moderate effect
H = High effect

TABLE 5-1. SUMMARY OF ENVIRONMENTAL RESULTS - PREPARATION PLANT NO. 1 (Continued)

Waste Stream	Total Discharge Severity		Major Contributors (Discharge Severity 10)		Biological Results		Conclusions	Recommendations
	Health	Eco-logical	Health	Eco-logical	Health	Eco-logical		
Fine Waste Slurry * Filtrate	1E1	7E1	NH_3-N	NH_3-N	N.C.	N.C.	• Potentially hazardous according to SAM/1A evaluation.	• Should not discharge directly to offsite surface waters; should be treated onsite.
Feedwater Filtrate *	7E-1	1E1	-	-	L.N.	N.C.	• Low potential for hazard according to TDS values and bioassay test results.	
Pond Water No. 1 * Filtrate	2E0	3E1	-	NH_3-N	M	M	• Potentially hazardous for ecological-based SAM/1A evaluation. • Complied with most stringent state effluent regulations for states in Eastern, Midwest and Northern Appalachian coal regions.	• Further characterization during Level 2 environmental assessment phase to determine origin of ammonia.
Pond Water No. 2 * Filtrate	7E-1	1E1	-	-	M	M		
Pond Water No. 3 * Filtrate	1E0	2E1	-	-	M	M		
ROM Storage Pile Runoff	2E0	3E1	-	NH_3-N	L.N.	N.C.	• Low potential hazard for health-based criteria. • Potentially hazardous for ecological-based criteria. • Water quality results in compliance with most stringent state effluent regulations.	• Collect runoff and treat for control of manganese. • Further characterization during Level 2 environmental assessment phase to determine origin of ammonia.
Clean Coal Storage Pile Runoff	1E1	1E2	-	Mn, Ni, NH_3-N	L.N.	N.C.		
Coarse Refuse Pile Runoff	9E0	4E1	-	Mn	L.N.	N.C.		

N.C. = Not conducted
L/N = Low or nondetectable effect
M = Moderate effect
H = High effect

TABLE 5-2. SUMMARY OF ENVIRONMENTAL RESULTS - PREPARATION PLANT NO. 2

Waste Stream	Total Discharge Severity		Major Contributors (Discharge Severity >10)		Biological Results		Conclusions	Recommendations
	Health	Ecological	Health	Ecological	Health	Ecological		
ROM Coal Storage Pile Fugitive Particulates	1.3E-2	2.0E-3	-	-	M	N.C.	• Low potential for hazard according to TDS values; however, potentially hazardous based on health-related bioassay test results. • Particulate morphology shows coal in all but upwind samples. • TSP values for fugitives below primary standard, except rotary breaker.	• Improve techniques for control of fugitive emissions.
Rotary Breaker Fugitive Particulates	1.1E-2	6.0E-3	-	-	M	N.C.		
Upwind Fugitive Particulates	1.2E-2	2.0E-2	-	-	M	N.C.		
Downwind Fugitive Particulates	1.1E-2	3.0E-3	-	-	M	N.C.		
ROM Coal Storage Pile Vapors	7.9E0	3.0E-1	-	-	L/N	N.C.	• Low potential for hazard according to TDS values and bioassay test results.	
Rotary Breaker Vapors	6.7E0	1.0E-1	-	-	L/N	N.C.		
Upwind Vapors	7.7E0	3.1E-1	-	-	L/N	N.C.		
Downwind Vapors	1.2E1	9.0E-1	-	-	L/N	N.C.		
Fine Waste Slurry Filtrate (bio. tests conducted on raw slurry)	2.0E0	1.0E1	-	-	H	M	• Uncertain potential hazard according to ecological-based SAM/IA evaluation. Potentially hazardous based upon bioassay test results.	• Should not discharge directly to offsite surface waters; should be treated onsite.
Desilting Pond Water Filtrate (bio. tests conducted on raw pond water)	1.4E0	8.0E0	-	-	M	M		

N.C. = Not conducted
L/N = Low or nondetectable effect
M = Moderate effect
H = High effect

TABLE 5-2. SUMMARY OF ENVIRONMENTAL RESULTS - PREPARATION PLANT NO. 2 (Continued)

Waste Stream	Total Discharge Severity		Major Contributors (Discharge Severity >10)		Biological Results		Conclusions	Recommendations
	Health	Ecological	Health	Ecological	Health	Ecological		
Transfer Pond Water Filtrate (bio. tests conducted on raw pond water)	1.4E0	1.5E1	-	-	L/N	N.C.	• Low potential for hazard according to health-based criteria. • Uncertain hazard potential according to ecological TDS values.	• Should not discharge directly to offsite surface waters; should be treated onsite.
Runoff Pond Water Filtrate (bio. tests conducted on raw pond water).	2.6E0	1.8E1	-	-	L/N			
ROM Coal Storage Pile Runoff	2.0E0	1.6E1	-	-	L/N	N.C.	• Low potential for hazard according to health-based criteria. • Uncertain hazard potential according to ecological TDS values.	• Collect runoff for treatment.
Clean Coal Leachate	2.2E0	3.5E1	-	NH_3-N	L/N	M	• Uncertain hazard potential according to ecological-based criteria. • Chemical constituents are more leachable in the coarse refuse than other solids. • Coarse refuse already stored in closed system.	• Use RCRA's EP Method for leachability to investigate leaching potential under acid conditions. • Should not discharge pond waters directly to offsite surface waters. • If discharged, treat for trace metals control. • Check origin of nitrogen compound in samples.
ROM Coal Leachate	4.0E0	6.7E1	-	NH_3-N	L/N	M		
Coarse Refuse Leachate	1.0E1	2.0E-2	-	NH_3N,Mn,Ni	L/N	M		
Desilting Pond Sediment Leachate	4.1E0	2.0E1	-	-	L/N	M		
Transfer Pond Sediment Leachate	8.4E-1	1.2E1	-	-	L/N	M		
Runoff Pond Sediment Leachate	9.2E0	3.3E1	-	Mn	L/N	M		
Desilting Pond Water Filtered Solids	6.5E1	4.1E1	Mn,Hg	P	M	N.C.	• Uncertain hazard potential according to SAM/IA evaluation and health-based bioassay test results.	• Retain material onsite via sedimentation. • Check forms of phosphorus.

N.C. = Not conducted
L/N = Low or nondetectable effect
M = Moderate effect
H = High effect

TABLE 5-2. SUMMARY OF ENVIRONMENTAL RESULTS - PREPARATION PLANT NO. 2 (CONTINUED)

	Total Discharge Severity		Major Contributors (Discharge Severity >10)		Biological Results			
Waste Stream	Health	Ecological	Health	Ecological	Health	Ecological	Conclusions	Recommendations
Transfer Pond Water Filtered Solids	4.1E2	6.1E1	Hg	P	L/N	N.C.	• Moderate potential for hazard based on SAM/1A evaluation. No or low hazard based on health-related bioassay test results.	• Retain material onsite via sedimentation. • Check forms of phosphorus.
Runoff Pond Water Filtered Solids	4.2E1	3.1E1	Mn,Hg	P	L/N	N.C.		
Desilting Pond Sediment	1.6E3	3.1E3	Mn,Ba,As, Cr,Pb,Li, Ni,P,V	P,Mn,V	H	N.C.	• High potential for hazard based on SAM/1A evaluation and health-related bioassay test results.	• Retain material onsite. • Check forms of phosphorus. • Further characterization during level 2 testing.
Transfer Pond Sediment	1.2E3	8.1E3	Cr,Mn,As, Ba,Cd,Pb, Li,Ni,P,V	P,Mn	H	N.C.		
Runoff Pond Sediment	4.3E2	1.0E4	Ba,As,Cd, Pb,Li,Ni, P,V	P,Cd,Ni	H	N.C.		
Coarse Refuse	2.1E3	1.0E4	Mn,Pb,Se, As,Ba,Cd, Cr,Li,Ni, P,V	P,Pb,Mn	L/N	N.C.	• High potential for hazard based on SAM/1A evaluation. Low or no hazard based on health-related bioassay results.	• Store coarse refuse in a closed system. • Check forms of phosphorus.

N.C. = Not conducted
L/N = Low or nondetectable effect
M = Moderate effect
H = High effect

In all liquid waste streams from both plants, ammonia was present at significant levels. However, since there is no physical or chemical reason for ammonia to be present, it was recommended that the protocol for analyzing ammonia be reviewed to determine if the present of ammonia was a result of interference during analysis (by certain cations, turbidity, or color) of if the origin of ammonia was from coal mining activities or biological activity.

Solids and Leachate Waste Streams--

As expected, the pond sediments and fine waste solids contained heavy metals and other elements at concentration ratios suggesting further analyses. These elements originate in the coal and the cleaning process is intended to remove incombustibles as refuse from the coal. The high metals concentrations in the refuse emphasizes the concern over their ultimate disposal and that precautions must be taken to prevent the migration of these chemicals to the groundwater.

The leachates from the ROM coal and clean coal from both plants had considerably smaller potentials for problems.

The pond sediments leachates (both plants), the coarse refuse leachate and the pondwaters from Plant No. 2 showed the highest potential for problems based on the ecological DMEG values and bioassay results. The sediment leachate chemical concentrations were much higher than the pond waters. This is undoubtedly due to the dilution of the pond water by plant influent and precipitation.

ENVIRONMENTAL TRADEOFFS

Coal washing reduces SO_2 emissions by 20 to 50 percent and decreases the particulate loading in the flue gas by 25 to 80 percent while increase-ing solid wastes by 25 to 150 percent. In contrast, the contribution from coal preparation plants' activities (excluding thermal dryers) to ambient total suspended particulate concentrations was found to be significantly less than the 24-hour primary and secondary ambient air quality standards of 260 ug/m^3, and 150 mg/m^3, respectively. Recent studies by the EPA Office of Air Quality Planning and Standards concluded that it is unnecessary to control any gaseous air pollutants from preparation plants.(18)

For liquid discharges from preparation plants, the constituents of concern are manganese, iron, and nickel. However, for most plants, the liquid waste streams are not discharged directly to surface waters. They are either sent to desilting ponds, where the solids settle out, or they are mechanically filtered. The decant is recycled back to the plant. Most preparation plants discharge some water to control dissolved solids concentrations and maintain the plant water balance.

The major environmental impact from coal washing is the generation of large quantities of refuse, composed of minerals, shales, and clays. Also, it has been estimated that about 3 to 10 percent of the mined coal is disposed of as waste.

The overall net effect of coal washing on solid wastes is to partially transfer waste generation from the point of use (i.e., power plant) back to the point of origin (i.e., coal mine and preparation). This results in a major environmental advantage. Air emissions of coal constituents which are emitted upon combustion are minimized by their removal as solid waste during coal washing. By disposing of non-volatiles (i.e., ash) at the preparation plant rather than at the user's site, they are neither transported, handled at the power plant, nor burned in the boilers.

The transfer of wastes from the power plant to the preparation plant has no apparent effect on water quality. Table 5-3 compares the quality of preparation plant refuse pond waters with ash pond waters. As shown, the quality of the pond waters are remarkably similar. Additionally, the

TABLE 5-3. PROPERTIES OF COAL REFUSE AND BOILER ASH POND DISCHARGE WATERS(16, 19)

Water parameter	Range of concentration (mg/l)	
	Coal Refuse Pond	Ash Pond
Total suspended solids	7-16	25-100
Hardness	100-220	200-750
Alkalinity	30-200	30-400
SO_4	80-400	100-300
Al	0.07-2.7	0.2-5.3
Cr	0.004-0.006	0.1
Na	> 6-285	20-173
NH_3	< 0.1-1.2	0.1-2
NO_3	0.04-1.0	0.1-6.1
Cl	10-85	20-2000
Cu	< 0.001-.02	0.1-0.3
Fe	0.08-1.8	0.02-2.9

Best Available Technology Economically Achievable (BAT) effluent limitations for ponds in the coal preparation industry and steam electric industry are similar for total suspended solids, as shown below:

BAT Effluent Limitations - TSS

	Maximum for any 1 day mg/l	Average of daily values for for 30 days mg/l
Preparation Plant Refuse Pond	70	35
Power Plant Ash Pond	100	30

and both require the discharge pH to be between 6.0 and 9.0.

The amount of solid waste produced by coal washing is dependent upon the method of mining, coal washability, the plant yield, and the input coal quantity to the preparation plant. The major environmental tradeoffs from burning clean coal versus burning a raw coal are quantified for eight different coals in Table 5-4. Two additional examples are discussed below.

Versar has calculated the amount of wastes produced per 100 x 10^6 Btu when a relatively non-cleanable coal, such as Kentucky No. 9 or No. 11 is burned raw (scenario I) compared to when it is washed and then burned (scenario II). When the raw coal is burned, 1.03 tons of fly ash and bottom ash are produced at the power plant. If the coal is washed, 2.82 tons of coal refuse are produced at the preparation plant (a rather inefficient 60 percent weight yield) while only 0.54 tons of ash are produced at the power plant. This 200 percent increase in solid wastes results in a 22 percent reduction in SO_2 emissions, from 0.36 tons to 0.28 tons SO_2/100 x 10^6 Btu.

In contrast, Versar has investigated the same scenarios with a coal preparation plant that operates with a 75 percent weight yield on a more cleanable coal (e.g., Illinois No. 6). When the raw coal is burned 1.48 tons of ash are produced at the power plant per 100 x 10^6 Btu. When the

TABLE 5-4. ENVIRONMENTAL TRADEOFFS BETWEEN RAW AND CLEAN COAL IN FUEL CYCLE

Coal	Energy Content		% Ash Content		% Sulfur		Weight Yield %	Raw Coal Power Plant Ash T/100 X 10^6 Btu	Preparation Wastes T/100 X 10^6 Btu	Clean Coal Power Plant Ash T/100 X 10^6 Btu	SO_2 Removal (%) T/100 X 10^6 Btu	Additional Solid Waste (%) T/100 X 10^6 Btu
	Raw	Clean	Raw	Clean	Raw	Clean						
Illinois #5	8,156	10,500	32.1	10.5	2.55	2.48	70	1.97	2.04	0.50	(24.5) 0.076	(29) 0.57
Indiana #3	9,700	10,879	23.6	10.9	4.85	3.62	65	1.22	2.47	0.50	(32.7) 0.162	(143) 1.75
Pittsburgh/ Sewickly	9,500	12,500	30.0	9.5	3.0	2.80	70	1.58	1.71	0.38	(29.2) 0.092	(32) 0.51
Ohio No. 6	10,000	11,321	20.1	9.9	3.2	2.2	80	1.01	1.10	0.44	(39.3) 0.126	(53) 0.53
Sewickley	11,000	11,421	32.0	16.3	2.3	2.0	75	1.45	1.46	0.71	(16.3) 0.034	(50) 0.72
Pittsburgh No. 8	11,676	13,210	22.5	8.0	1.4	1.3	80	0.96	0.95	0.30	(18.0) 0.022	(30) 0.29
Kentucky No. 11	8,728	12,760	37.5	10.5	3.8	3.4	67	2.15	1.93	0.41	(38.7) 0.168	(9) 0.19
Illinois No. 5	7,950	10,550	15.9	10.5	3.5	2.4	72	1.0	1.84	0.49	(48.4) 0.213	(133) 1.33

coal is washed 1.38 tons of coal refuse are produced at the preparation plant and only 0.53 tons of ash are produced at the power plant. There is a 29 percent overall increase in solid wastes but a 64 percent reduction in solid wastes at the power plant. The increase in coal quality represents a 49 percent reduction in SO_2 emissions.

Table 5-4 shows that the environmental tradeoffs always show an increase in solid waste production for decrease in SO_2 emissions. The table also shows that for every ton of SO_2 removed, from 1 to 20 tons of solid waste are generated. These quantities vary with such factors as ash content of the coal, product specifications, and type or level of washing employed. However, pollutants that would have been emitted to the air are now transformed into solid waste through coal preparation. These pollutants are more easily controlled in a solid form and the controls are significantly less expensive than flue gas treatment. Potential environmental problems such as infiltration of contaminated water from tailing ponds containing fine solid wastes can be controlled by the inclusion of an impervious linear, or the use of collection ditches and treatment systems. Maintenance of the pH above 7 within the pond reduces the concentrations of many undesirable pollutants.

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SECTION 6.0

CLEANING PLANT COST ESTIMATES AND COAL CLEANING COST/BENEFIT FACTORS

The following covers (1) a capital cost estimating methodology, (2) an operating and maintenance estimating procedure, and (3) cost/benefit factors relating to the use of a cleaned coal. Each of the above is addressed independently.

It is emphasized that unlike the manufacture of certain chemicals and metals where a specific process will give reasonably constant results, there is no universal approach to the production of clean coal by physical preparation techniques. This occurs due to the substantial variability in the physical and chemical composition of coal from seam to seam and even within the seam itself. Therefore, a given preparation process that is effective with a coal from one seam may be inappropriate for a coal from another seam in achieving a comparable level of cleaning. For this reason, the particular approach taken to coal cleaning must be designed around the specific coal and the desired end results within the economic constraints of the situation. Variabilities are such that cleaning cost trends as related to level of cleaning, plant size, and plant yield must be addressed with considerable caution. In general, each situation with its generally unique parameters must be independently addressed. Even so, some general trends can be cited. Other factors being equal and within bounds, larger plants due to economy of scale cost less per ton per hour input capacity. In a like manner operating labor does not generally increase proportionately with plant size. As coal is cleaned at smaller topsizes, both labor and capital cost generally increase. As yield decreases, a given size plant has less throughput with resulting higher cost. When coals are difficult to clean, the plant may utilize more complex circuits, and finer topsize coals may be processed. The cost of cleaning for these plants is generally higher than that for plants handling easier to clean coals.

CAPITAL COST

This section provides a methodology for estimating the capital cost of a coal cleaning plant of arbitrary capacity. The capital cost estimate is influenced by the capacities of the various circuits and ancillaries which could include such items as load-out facilities, dryers, and site specific load-in arrangements.

The capital cost estimating approach for this methodology is based on specific plant circuits, on their associated capacities, and on EPA-600/8-79-018a, A Standard Procedure for Cost Analysis of Pollution Control Operations. Basically, the cost estimating approach is based on the cost of the major plant items (MPIs) of which the cleaning plant consists. For the basic (grass-root) plant, the capital costs estimate is directly based on the total cost of the MPIs in the plant. The overall plant capital cost is then the cost of the basic plant (as based on the MPIs) plus the installed cost of items outside the basic plant such as silos, external conveyors, and thermal dryers.

The cost estimating procedure can be simplified if the MPI's costs are definable in terms of design throughput values of the cleaning plant circuits. In this regard, flowsheets for a number of cleaning plant configurations are provided by Appendix C. The flowsheets in Appendix C (Figures 6C-1 through 6C-5) clearly indicate groupings of MPIs in terms of the cleaning plant circuits. Therefore, for given circuits, relationships between the cost of MPIs and throughput parameters can be developed. The cost of MPIs in the overall plant can then be defined in terms of circuit design and throughput parameters. The estimating procedure provided in this methodology is based on this approach.

For a number of circuits, cost estimates for major plant items are provided for a range of circuit capacities. Therefore, given a specific plant composition and the design capacities of the component circuits, an estimate of the cost of the MPIs in the basic plant is defined. The cost of the MPIs is then used to provide an estimate of the basic grass root plant cost. Items outside of the basic or grass root plant, such as silos, are costed separately (as appropriate).

The following are provided:

- The costing criteria for individual plant items.
- Coal cleaning circuits assessments consisting of
    1. Circuit configuration with sizing philosophy.
    2. Cost of MPIs for various coal input sizing values.
    3. Plot of cost of MPIs (per circuit) vs. coal input sizing value.
- Cost of some ancillaries that are outside of grass root cleaning plant.
- Capital cost estimating work sheets.

Costing Criteria for Plant Items

The supplied cost data is based on estimates provided by suppliers of the cleaning plant items. The cost basis, F.O.B. supplier shipping point, is January 1982. Supplier cost estimates based on a different time period were adjusted in accordance with the cost/time trend of cleaning plant equipment to reflect the January 1982 value.

The cleaning circuits are for a maximum topsize of 1-1/2 inch. Specifically, the coarse coal circuits cover 1-1/2 inch by 3/8 inch; the medium coal circuits handle 3/8 inch by 28 mesh; the medium/fine coal circuit handles 3/8 inch by 200 mesh; and the fine circuits treat minus 28 mesh.

This effort considers a "reasonable" minimum coal topsize of 3/8 inch after cleaning. Finer coal is needed for certain uses, such as coal/water slurry fuel or synthetic fuels production, but is outside the scope of this effort.

The (estimated) costs of major plant items considered in this study are provided in Appendix C. The items covered are:

- Crushers
- Screens
- Heavy media vessels
- Coarse size coal jigs
- Heavy media cyclones
- Intermediate size coal jigs
- Water-only cyclones
- Concentrating tables
- Froth flotation cells
- Centrifuges
- Sieve bends
- Dense media recovery systems
- Vacuum disc filters
- Static thickeners
- Slurry feed pumps
- Tanks

Cost Assessments of Coal Cleaning Circuits

The following is the assessment of the cost of the MPIs by circuit as a function of circuit design capacity. For each of the considered circuits, the following is provided.

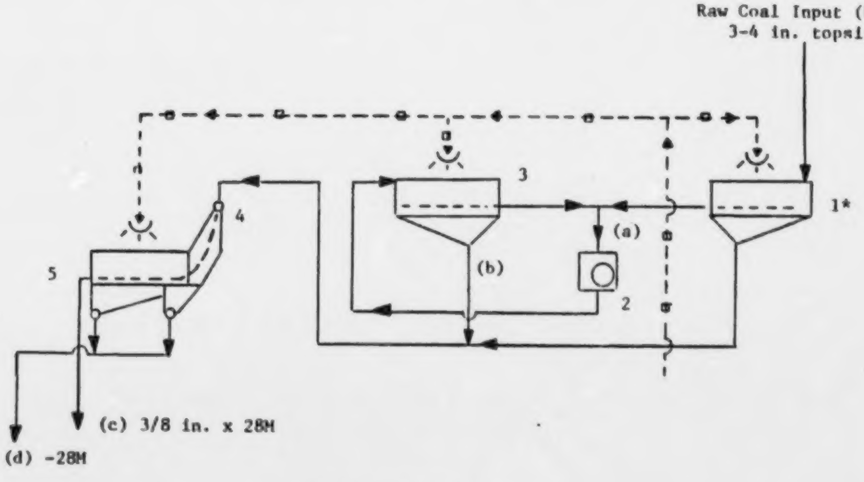
- General circuit description
- Schematic of circuit configuration including sizing philosophy based on circuit input capacity
- MPI (equipment) costs based on the circuit input capacity

- A cost vs. capacity curve indicating the sum of the MPI costs versus circuit design capacity

For the above, thickeners are presented separately since the indicated cost is the installed cost rather than the equipment cost.

Coal Sizing - Two Size Increments--

The raw coal sizing, two size increments circuit (Figure 6-1) reduces 3 to 4 inch topsize feed coal to a 3/8 inch by 28 mesh fraction and a minus 28 mesh fraction. The minus 3/8 inch size fraction is screened out of the raw coal feed and delivered to the output sieve bends. The remaining plus 3/8 inch fraction is pulverized to a topsize slightly in excess of 3/8 of an inch. The minus 3/8 inch material out of the pulverizer reports to the output sieve bends, and the plus 3/8 inch material is recycled to the crusher. The sized coal is separated into 3/8 inch by 28 mesh and minus 28 mesh fractions by sieve bends followed by screens. As indicated by Figure 6-1, wet size classifying is used throughout the circuit. Equipment designations and costs for two size increments are given in Table 6-1. A plot of the sizing circuit capacity versus the sum of MPI sizing circuits costs is given in Figure 6-2.



Sizing Philosophy:
(a) max. 0.80 RCI (b) max. 0.8 RCI
(c) max. 1.0 RCI (d) max. 0.2 RCI

FIGURE 6-1. RAW COAL SIZING - TWO SIZE INCREMENTS
(* component item number, typical)

TABLE 6-1. MPI COST FOR RAW COAL SIZING - TWO SIZE INCREMENTS
(3/8 in. x 28M, and minus 28M)

Item No.	Item	300 tph Input	400 tph Input	500 tph Input	600 tph Input
1	Raw Coal Screens	1,8'x16' $40.4K	2,6'x14' $54.4K	2,7'x16' $71.2K	2,8'x16' $80.8K
2	Crushers	$104K	$116K	$152k	$164K
3	Crusher Screens	2,6'x16' $61.6K	2,8'x16' $80.8K	3,7'x16' $108.8K	3,8'x16' $121.2K
4	Sieve Bends	6,6'wide $41.3K	8,6'wide $55K	8,7'wide $64.8K	10,7'wide $81K
5	Finish Screens	6,7'x16' $213.6K	8,7'x16 $284.8K	8,8'x16' $323.2K	10,8'x16' $404K
	Totals	$460.9K	$591K	$720K	$851K

Note: 1,8'x16' indicates one screen 8'x16' (typical)

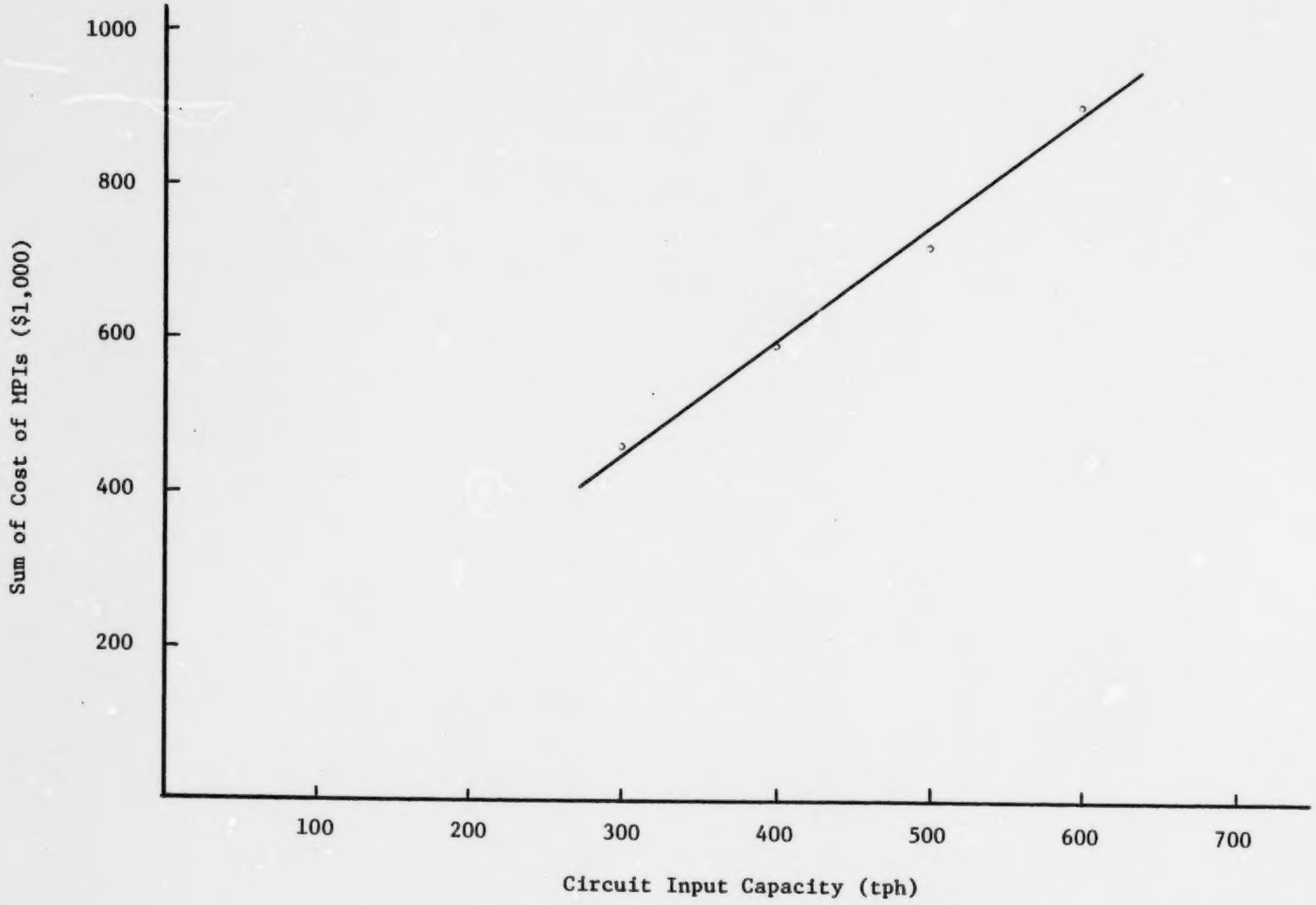
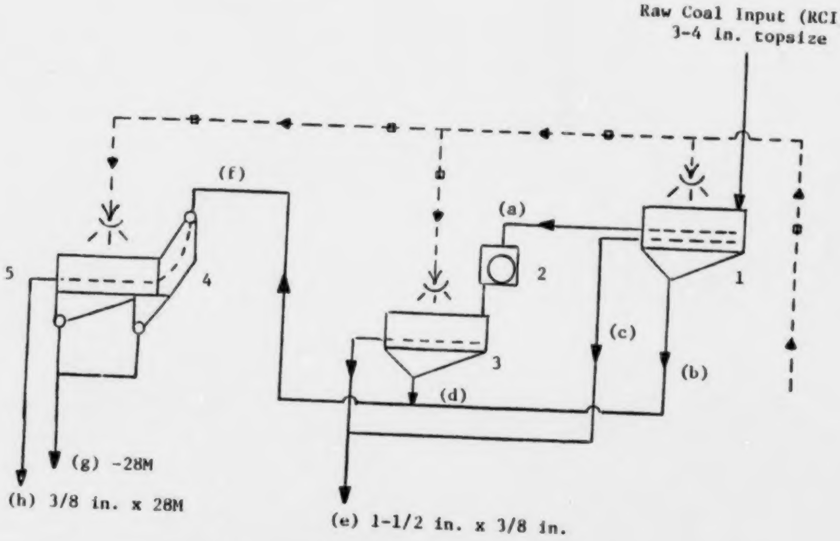


FIGURE 6-2. RAW COAL SIZING - TWO SIZE INCREMENTS

Coal Sizing - Three Size Increments--

The raw coal sizing, three size increments circuit reduces 3 to 4 inch topsize feed coal to a 1-1/2 inch by 3/8 inch fraction, a 3/8 inch by 28 mesh fraction, and a minus 28 mesh fraction. The 1-1/2 inch by 3/8 inch and the minus 3/8 inch fractions are screened from the raw coal feed. The plus 1-1/2 inch portion of the raw coal feed is crushed to 1-1/2 inch topsize and screened to separate the plus 3/8 inch and minus 3/8 inch fractions. As indicated by Figure 6-3, all of the 1-1/2 inch by 3/8 inch coal reports out and the minus 3/8 inch coal is separated into a 3/8 inch by 28 mesh fraction and a minus 28 mesh fraction by sieve bends followed by screens prior to reporting out of the circuit. As indicated by Figure 6-3, wet (size) classifying is used throughout the circuit. Equipment costs are given in Table 6-2. A graph of MPI cost versus capacity is shown in Figure 6-4.



Sizing Philosophy:
(a) max. 0.25 RCI (b) max. 0.50 RCI (c) max. 0.50 RCI
(d) max. 0.25 RCI (e) max. 0.90 RCI (f) max. 0.75 RCI
(g) max. 0.20 RCI (h) max. 0.70 RCI

FIGURE 6-3. RAW COAL SIZING - THREE SIZE INCREMENTS

TABLE 6-2. RAW COAL SIZING - THREE SIZE INCREMENTS

Item No.	Item	300 tph Input	400 tph Input	500 tph Input	600 tph Input
1	Raw Coal Screens	2,5'x16' $66K	2,7'x16' $93.6K	2,8'x16' $106.4K	3,7'x16' $140.4K
2	Crushers	$40K	$48K	$77K	$80K
3	Crusher Screens	1,6'x16' $30.8K	1,8'x16' $40.4K	2,5'x16' $52K	2,6'x16' $61.6K
4	Sieve Bends	6,5'wide $36.9K	7,5'wide $43.1K	9,4'wide $48.2K	11,5'wide $67.7K
5	Finish Screens	6,7'x16' $213.6K	7,8'x16' $282.8K	9,8'x16' $363.6K	11,8'x16' $444.4K
	Totals	$387.3K	$508K	$647K	$794K

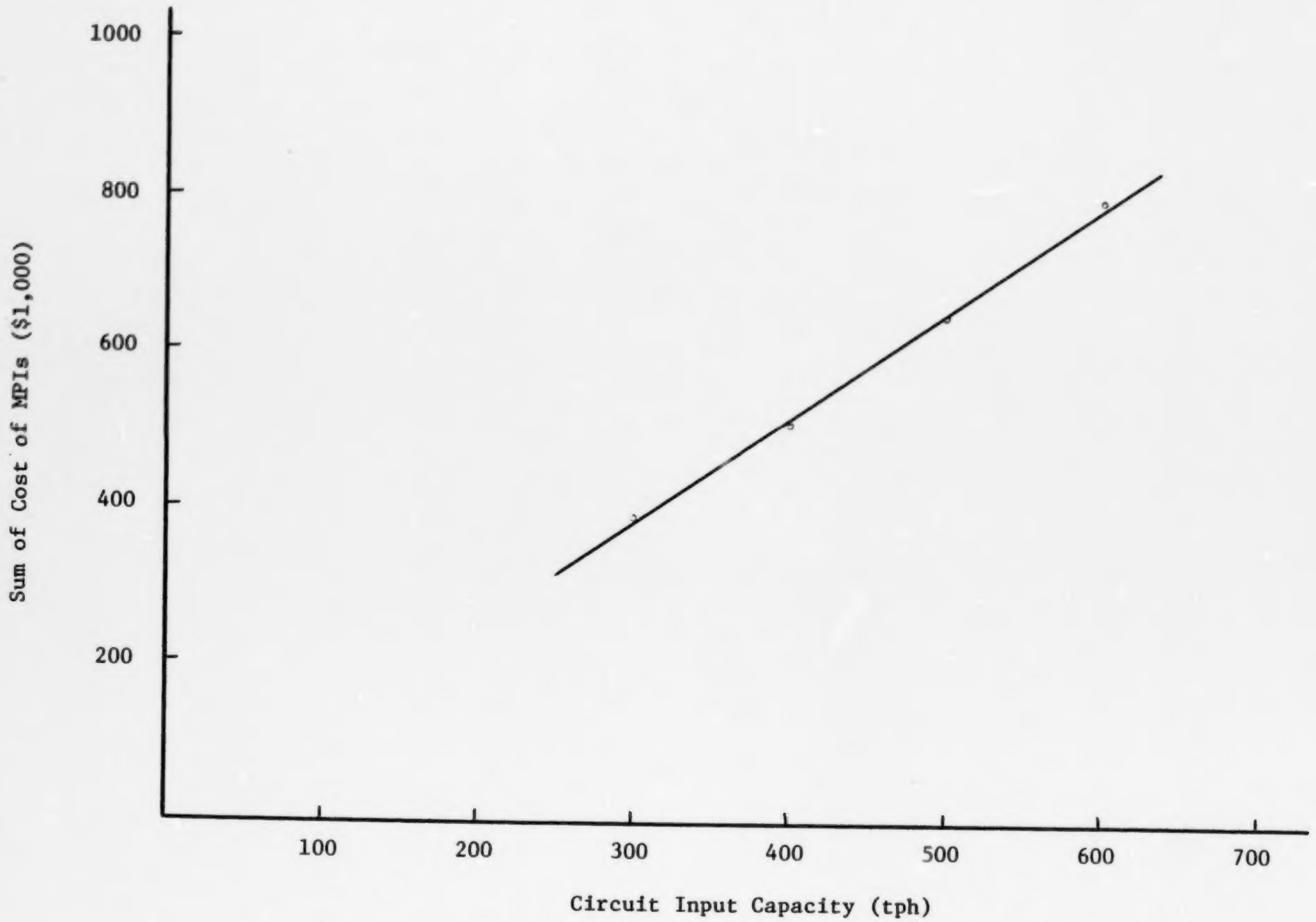
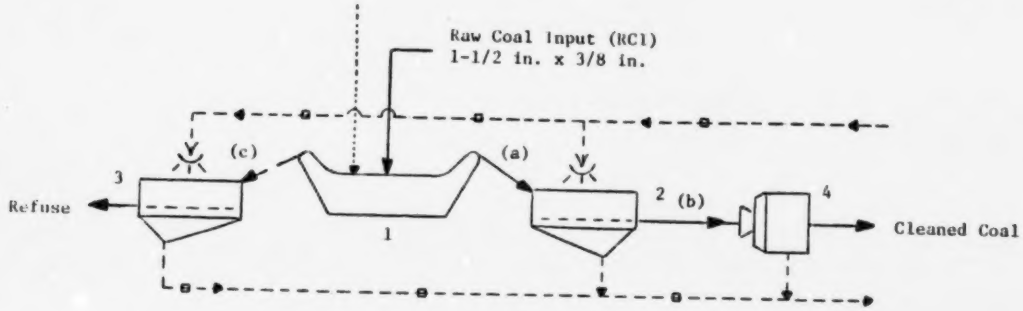


FIGURE 6-4. RAW COAL SIZING - THREE SIZE INCREMENTS

Coarse Size Coal Cleaning - Dense Medium Vessel--

Raw 1-1/2 inch by 3/8 inch coal is delivered to a D.M. vessel (see Figure 6-5) that has a bath of pulverized magnetite suspended in water to provide the desired specific gravity. The float material (i.e., clean coal) is rinsed of magnetite and partially dewatered via a (rinse) screen(s). The clean coal is then further dewatered by centrifuge(s). The refuse (sink material) is rinsed of the magnetite medium and partially dewatered via (rinse) screen(s) with the dewatered refuse available for disposal. The rinse magnetite medium is available for reporting to the magnetite recovery system.



Sizing Philosophy:
(a) max. 0.95 RCI (b) max. 0.95 RCI (c) max. 0.30 RCI

FIGURE 6-5. COARSE SIZE COAL CLEANING - DENSE MEDIUM VESSEL

TABLE 6-3. COARSE SIZE COAL CLEANING - DENSE MEDIUM VESSEL (1-1/2 in. x 3/8 in.)

Item No.	Item	200 tph Input	300 tph Input	400 tph Input	500 tph Input
1	D.M. Vessels	$60K	$101K	$120K	$161K
2	Clean Coal Screens	2,6'x16' $61.6K	2,8'x16' $80.8K	3,7'x16' $106.8K	4,7'x16' $142.4K
3	Refuse Screens	1,4'x16' $21.2K	1,5'x16' $26K	1,7'x16' $35.6K	2,5'x16' $52K
4	Coal Centrifuges	$36K	$60K	$72K	$96K
	Totals	$197K	$268K	$335K	$451K

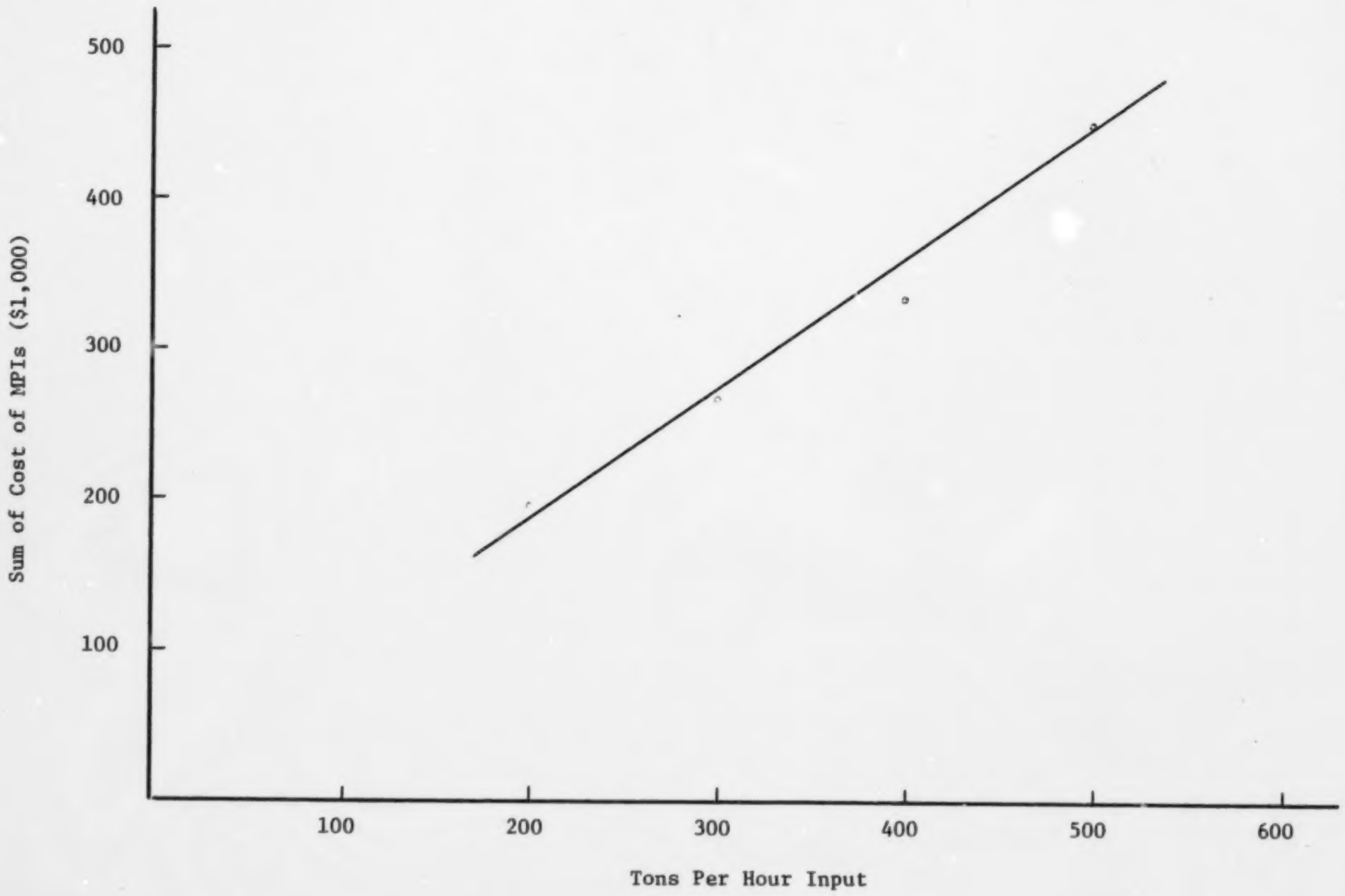
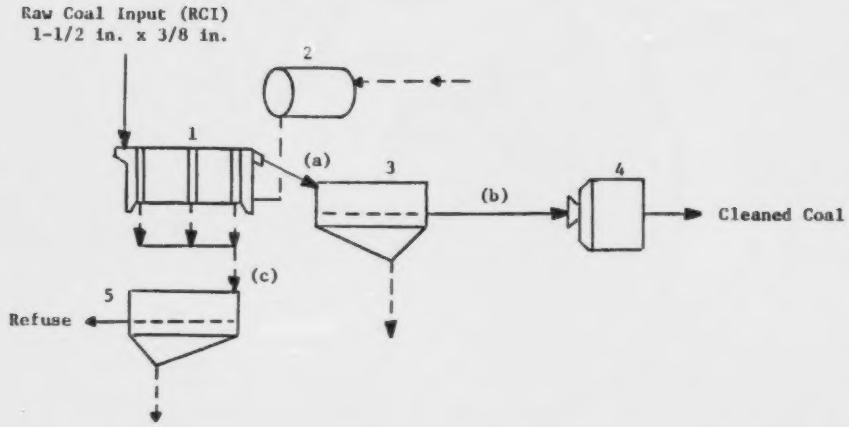


FIGURE 6-6. COARSE COAL CLEANING - DENSE MEDIUM VESSEL

Coarse Size Coal Cleaning - Water Jig

Raw 1-1/2 inch by 3/8 inch coal is fed to the (water only) jig (Figure 6-7) that provides an effective specific gravity due to the pulsating action of the water medium. The clean coal (float product) is dewatered via screen(s) and further dewatered by centrifuge(s). The refuse (sink material) is dewatered via screens and reports for disposal. The collected black drain water can be clarified and recycled.


Raw Coal Input (RCI)
1-1/2 in. x 3/8 in.
2
1
(a)
3
(b)
4
Cleaned Coal
(c)
5
Refuse

Sizing Philosophy:
(a) max. 0.95 RCI (b) max. 0.95 RCI (c) max. 0.30 RCI

FIGURE 6-7. COARSE SIZE COAL CLEANING - WATER JIG

TABLE 6-4. COARSE SIZE COAL CLEANING - WATER JIG
(1-1/2 in. x 3/8 in.)

Item No.	Item	200 tph Input	300 tph Input	400 tph Input	500 tph Input
1	Jigs (Water Only)	$172K	$195K	$195K	$220K
2	Jig Head Tanks	$10K	$10K	$10K	$10K
3	Coal Dewatering Screens	2,5'x16' $48K	2,8'x16' $76.8K	3,7'x16' $100.8K	4,7'x16' $134.4K
4	Centrifuge Dryers	$36K	$60K	$72K	$96K
5	Refuse Dewatering Screens	1,4'x16' $19.2K	1,5'x16' $24K	1,7'x16' $33.6K	2,5'x16' $48K
	Totals	$285K	$366K	$412K	$508K

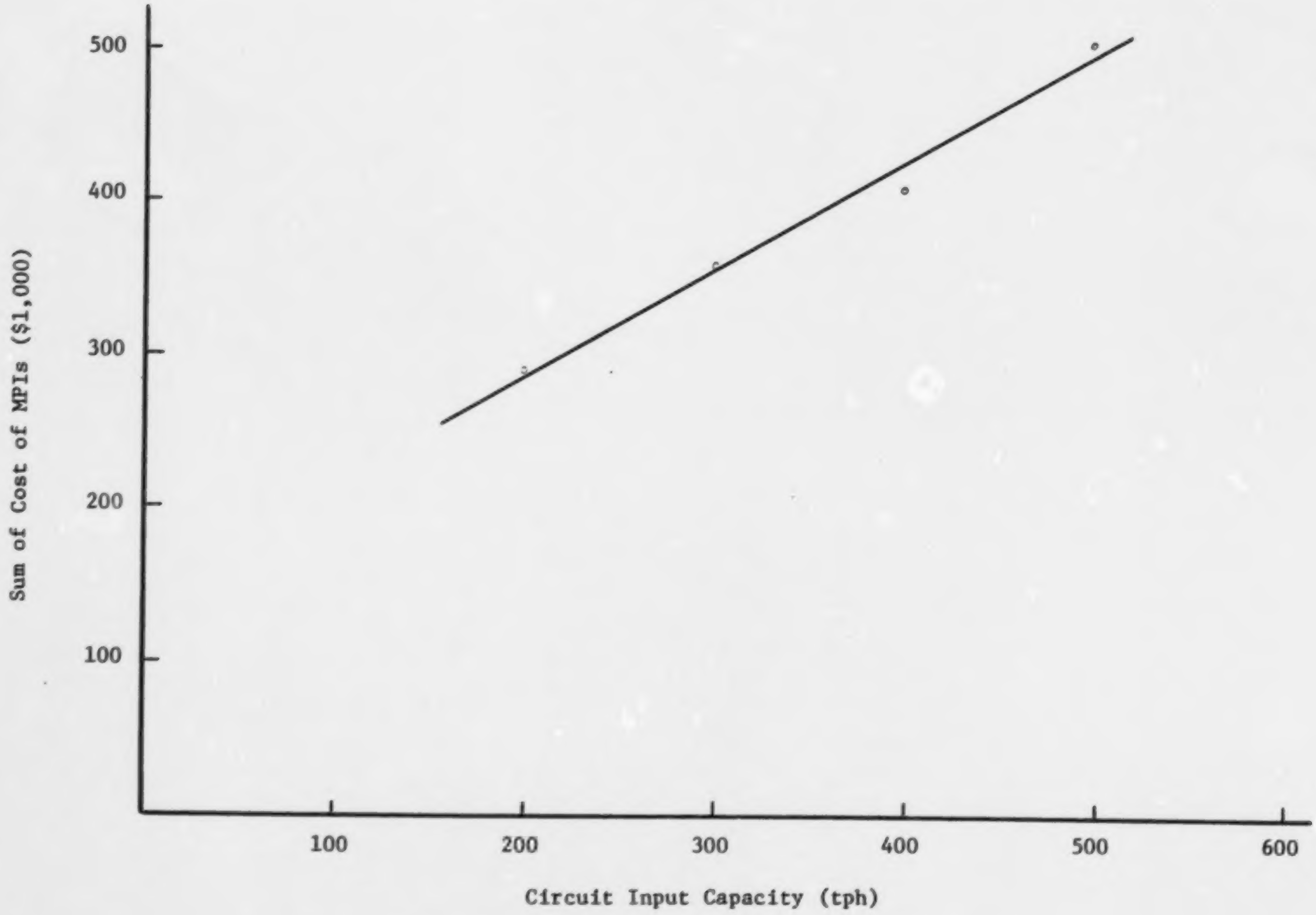
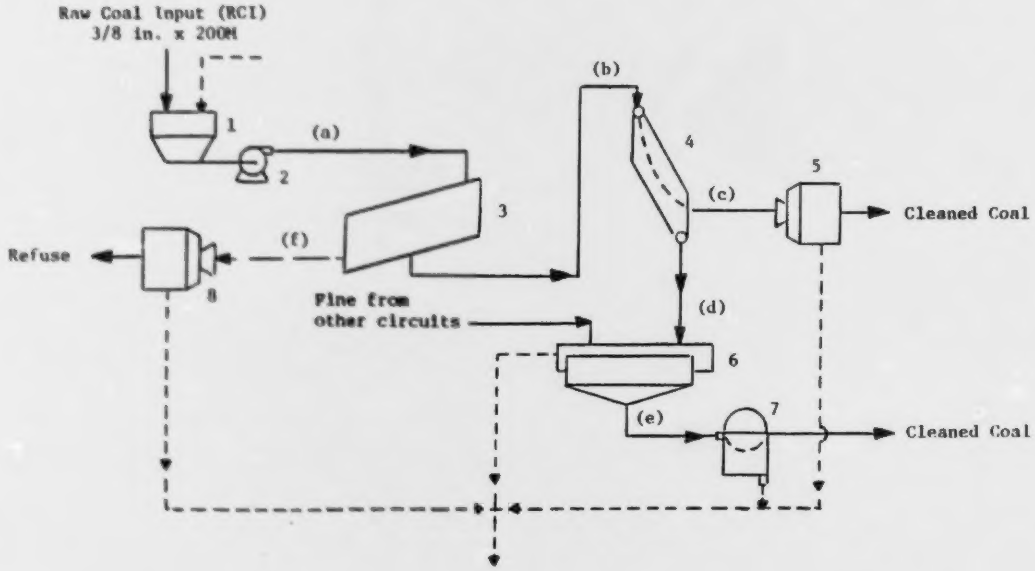


FIGURE 6-8.. COARSE SIZE COAL CLEANING - WATER JIG

Intermediate/Fine Size Coal Cleaning - Concentrating Tables--

Raw coal is fed to coal sumps (Figure 6-9) where the coal is mixed with water to form a coal slurry. The slurry is then fed to concentrating tables. The clean product from the tables is dewatered in sieve bends and then further dewatered by cyclones. The underflow from the sieve bends reports to a thickener. After dewatering by a disc filter, the thickened product reports to the cleaned coal output. The concentrating tables reject is dewatered via centrifuges prior to disposal.


Raw Coal Input (RCI)
3/8 in. x 200M
1
2
(a)
3
(b)
4
(c)
5
Cleaned Coal
Refuse
(f)
8
Fine from
other circuits
(d)
6
(e)
7
Cleaned Coal

Sizing Philosophy:
(a) max. 1.0 RCI (b) max. 0.95 RCI (c) max. 0.95 RCI
(d) max. 0.1 RCI (e) max. 0.1 RCI (f) max. 0.2 RCI

FIGURE 6-9. INTERMEDIATE/FINE SIZE COAL CLEANING - CONCENTRATING TABLE

TABLE 6-5. INTERMEDIATE/FINE SIZE COAL CLEANING - CONCENTRATING TABLE (3/8 in. x 200M)

Item No.	Item	100 tph Input	250 tph Input	400 tph Input	600 tph Input
1	Sumps	$6.6K	$19.8K	$26.4K	$39.6K
2	Pumps	$2.2K	$6.6K	$8.8K	$13.2K
3	Tables	$116K	$290K	$464K	$696K
4	Sieve Bends	2,6'wide $13.7K	3,8'wide $27.5K	5,8'wide $45.8K	7,8'wide $64.2K
5	Coal Centrifuges	$36K	$94K	$120K	$180K
6	Thickeners *	$220K	$240K	$290K	$330K
7	Disc Filters	$130K	$170K	$216K	$280K
8	Refuse Centrifuge	$34K	$34K	$36K	$60K
	Totals	$339K, $220K *	$642K, $240K *	$917K, $290K *	$1337K, $330K *

* Installed thickener cost

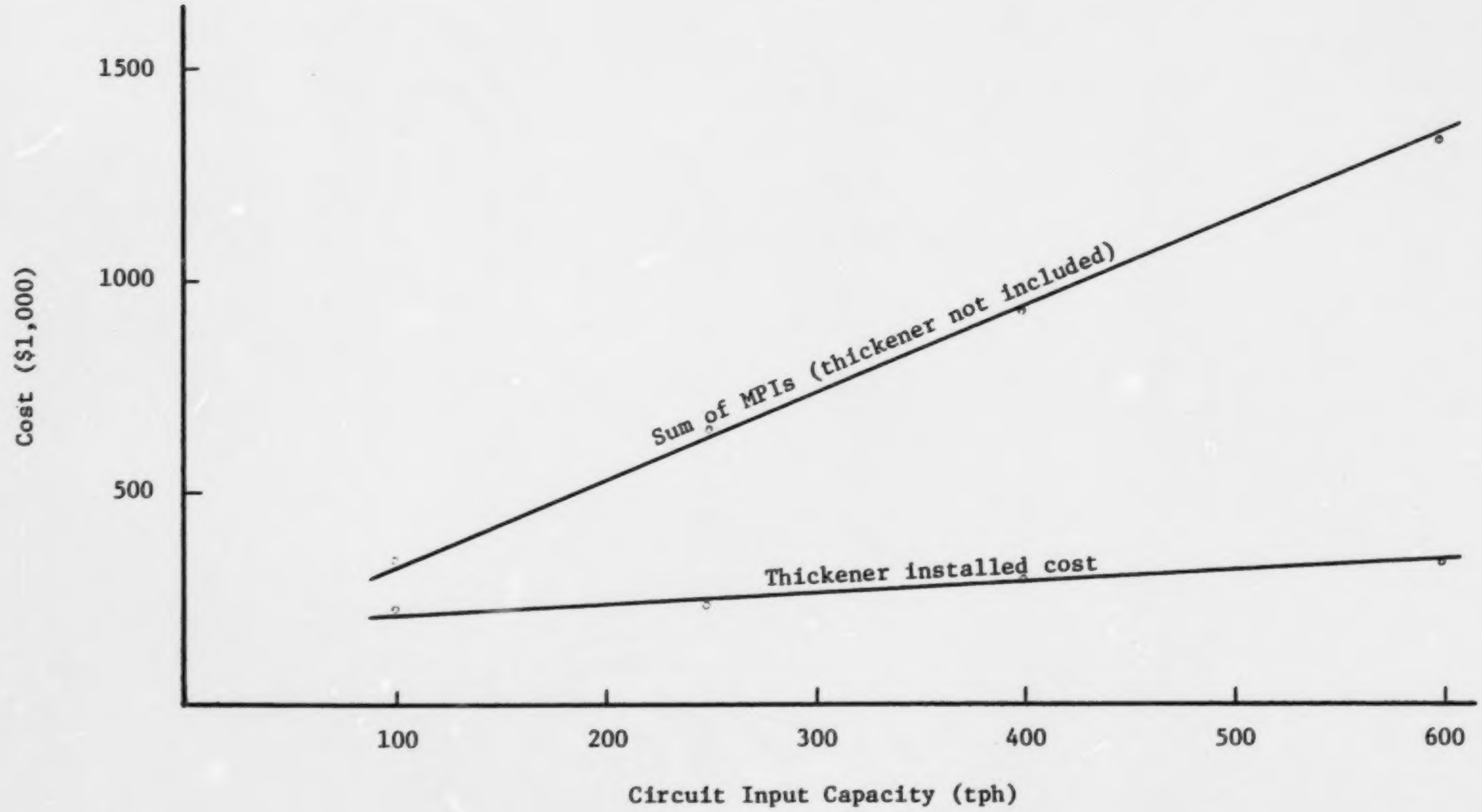
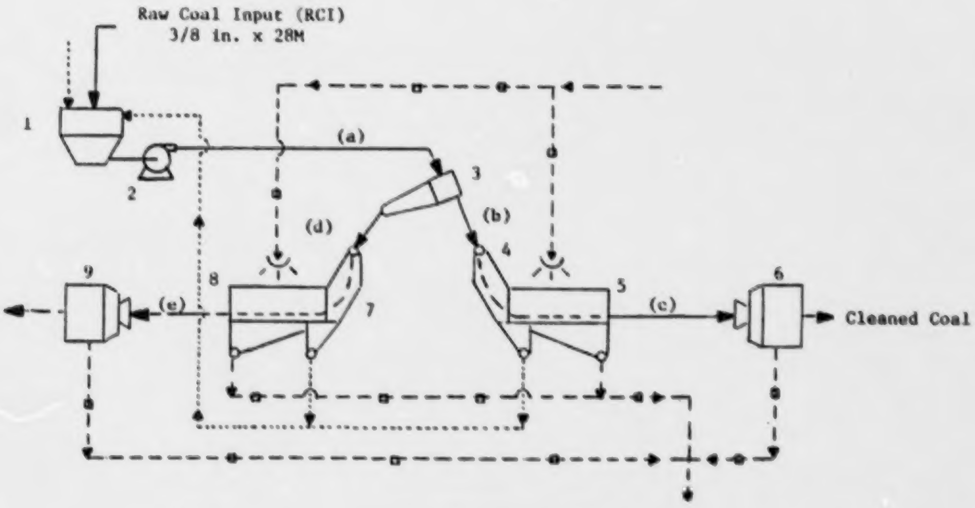


FIGURE 6-10. INTERMEDIATE/FINE SIZE COAL CLEANING - CONCENTRATING TABLE

Intermediate Size Coal Cleaning - D.M. Cyclone--

Raw coal is fed to coal sumps (Figure 6-11) where it is slurried with a water/magnetite solution. The coal slurry is then pumped to the D.M. cyclones. The cleaned coal product from the cyclones is drained, rinsed,and partially dewatered by sieve bends followed by screens. The partially dewatered coal is further dewatered by cyclones prior to reporting out. The cyclone reject fraction like the cleaned coal fraction, is drained, rinsed, and partially dewatered by refuse screens. The partially dewatered refuse is fed to a cyclone for further dewatering prior to disposal. The weak magnetite drain and rinse solution is collected for the magnetite recovery circuit.



Sizing Philosophy:
(a) max. 1.0 RCI (b) max. 0.95 RCI (c) max. 0.95 RCI
(d) max. 0.2 RCI (e) max. 0.2 RCI

FIGURE 6-11. INTERMEDIATE SIZE COAL CLEANING - D.M. CYCLONES

TABLE 6-6. INTERMEDIATE SIZE COAL CLEANING - D. M. CYCLONES (3/8 in. x 28M)

Item No.	Item	100 tph Input	200 tph Input	300 tph Input	400 tph Input
1	Sumps	$8.4K	$15.6K	$24K	$31.2K
2	Pumps	$8.4K	$12.6K	$21K	$25.2K
3	D.M. Cyclones	$10.5K	$21K	$31.5K	$42K
4	Sieve Bends	2,5'wide $12.3K	3,7'wide $24.4K	3,8'wide $27.5K	4,8'wide $36.7K
5	Coal Screens	2,5'x16' $52K	3,7'x16' $106.8K	3,8'x16' $121.2K	4,8'x16' $161.6K
6	Coal Centrifuges	$36K	$60K	$96K	$120K
7	Sieve Bends	1,3'wide $4K	1,5'wide $6.1K	1,7'wide $8.1K	2,5'wide $12.3K
8	Refuse Screens	1,3'x16' $16.4K	1,5'x16' $26K	1,7'x16' $35.6K	2,5'x16' $52K
9	Refuse Centrifuges	$34K	$34K	$36K	$36K
	Totals	$182K	$307K	$401K	$517K

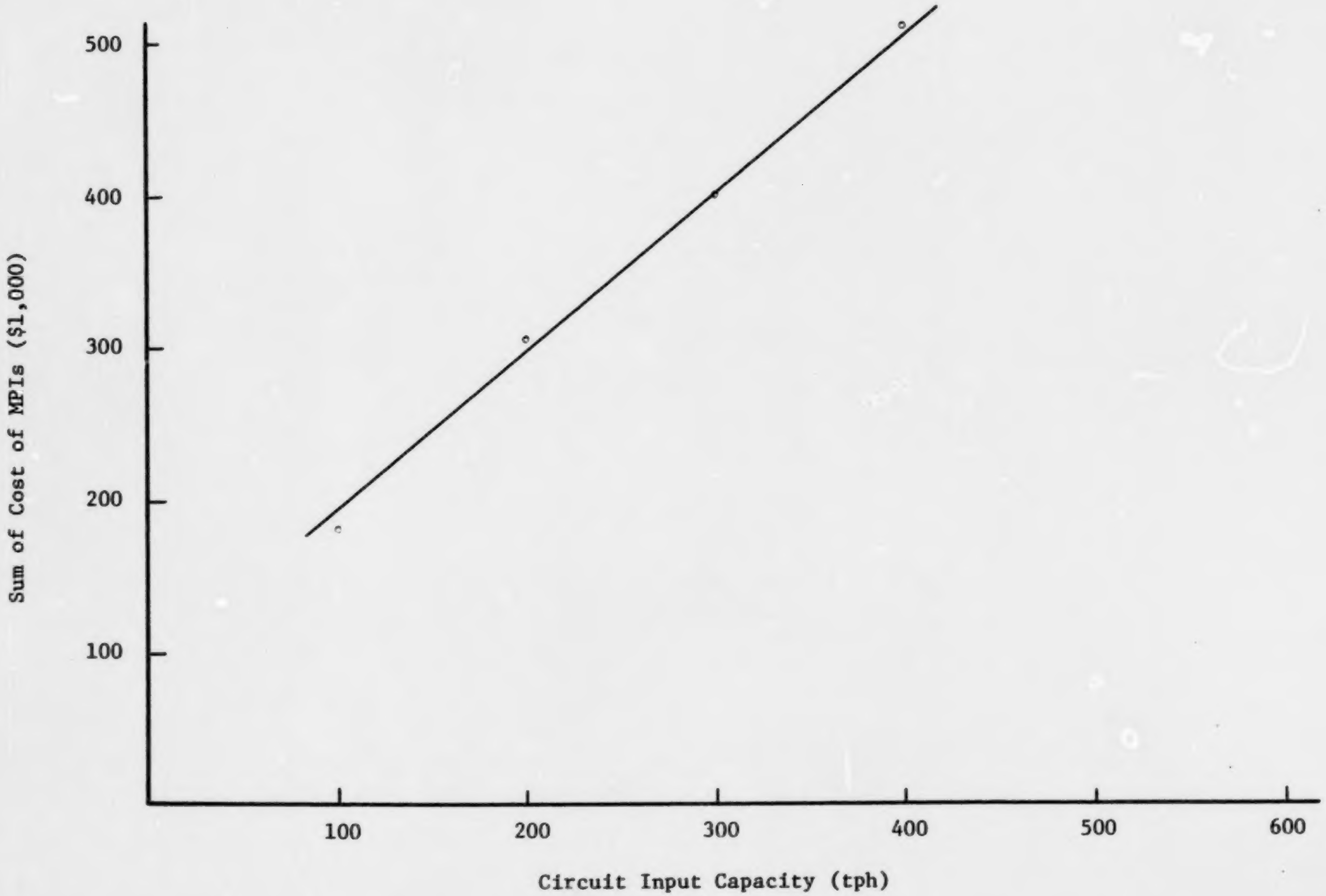
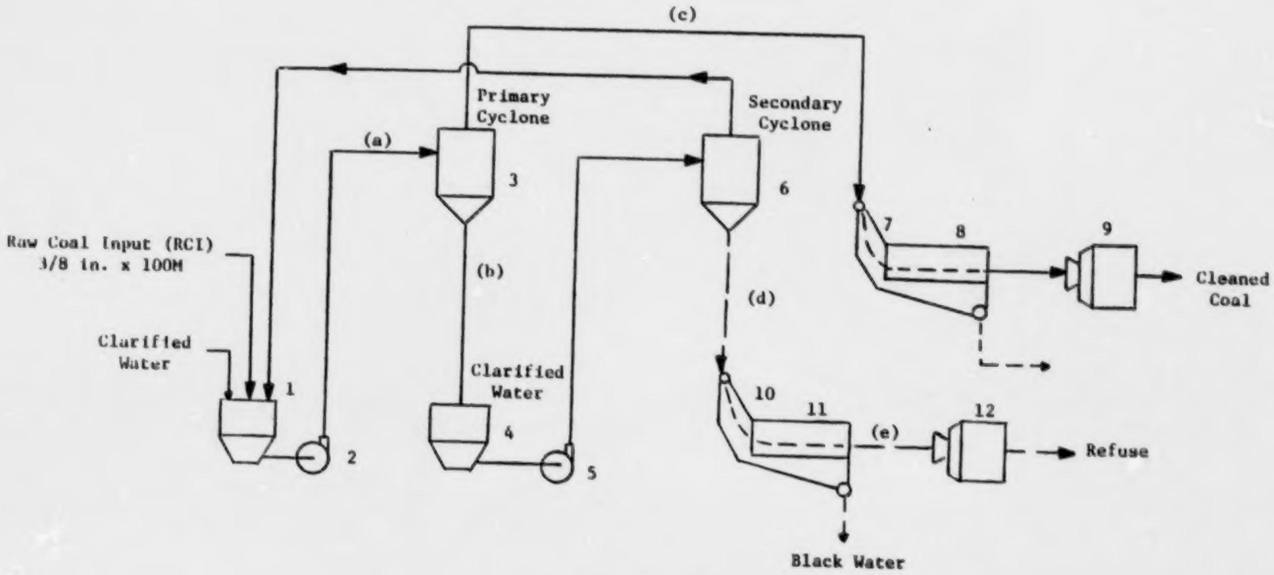


FIGURE 6-12. INTERMEDIATE SIZE COAL CLEANING - D.M. CYCLONES

Intermediate Size Coal Cleaning - Hydrocyclones--

Raw coal is fed to sumps where it is slurried with water (Figure 6-13). The slurried product is pumped to primary cyclones. The clean cyclone product (floats) is then partially dewatered by sieves and screens and further dewatered by cyclones prior to reporting out. The primary cyclone reject is slurried with water and fed to secondary cyclones. The secondary cyclones' lighter output fraction (floats) is routed to the input sumps for recycling. The secondary cyclone rejects (like the cleaned coal product) is partially dewatered by sieves and screens and further dewatered by cyclones prior to disposal.


(c)
Primary Cyclone
Secondary Cyclone
(a)
3
6
7
8
9
Raw Coal Input (RCI) 3/8 in. x 100M
(b)
(d)
Cleaned Coal
Clarified Water
1
Clarified Water
10
11
12
4
(e)
Refuse
2
5
Black Water

Sizing Philosophy:
(a) max. 1.0 RCI (b) max. 0.4 RCI (c) max. 0.95 RCI
(d) max. 0.2 RCI (e) max. 0.2 RCI

FIGURE 6-13. INTERMEDIATE SIZE COAL CLEANING - HYDROCYCLONES

TABLE 6-7. INTERMEDIATE SIZE COAL CLEANING - HYDROCYCLONES (3/8 in. x 100M)

Item No.	Item	100 tph Input	200 tph Input	300 tph Input	400 tph Input
1	Primary Sumps	$8.4K	$15.6K	$24K	$31.2K
2	Primary Pumps	$8.4K	$12.6K	$21K	$25.2K
3	Primary Cyclones	$20.8K	$41.6K	$62.4K	$83.2K
4	Secondary Sumps	$4K	$7K	$9.8K	$12.7K
5	Secondary Pumps	$414K	$416K	$7.6K	$10K
6	Secondary Cyclones	$11.8K	$16.3K	$23.6K	$35.4K
7	Sieve Bends	$12.3K	$24.4K	$27.5K	$36.7K
8	Coal Screens	$52K	$106.8K	$121.2K	$161.6K
9	Coal Centrifuges	$36K	$60K	$96K	$120K
10	Sieve Bends	$4K	$6.1K	$8.1K	$12.3K
11	Refuse Screen	$16.4K	$26K	$35.6K	$52K
12	Refuse Centrifuges	$34K	$34K	$36K	$36K
	Totals	$212.5K	$355K	$473K	$616K

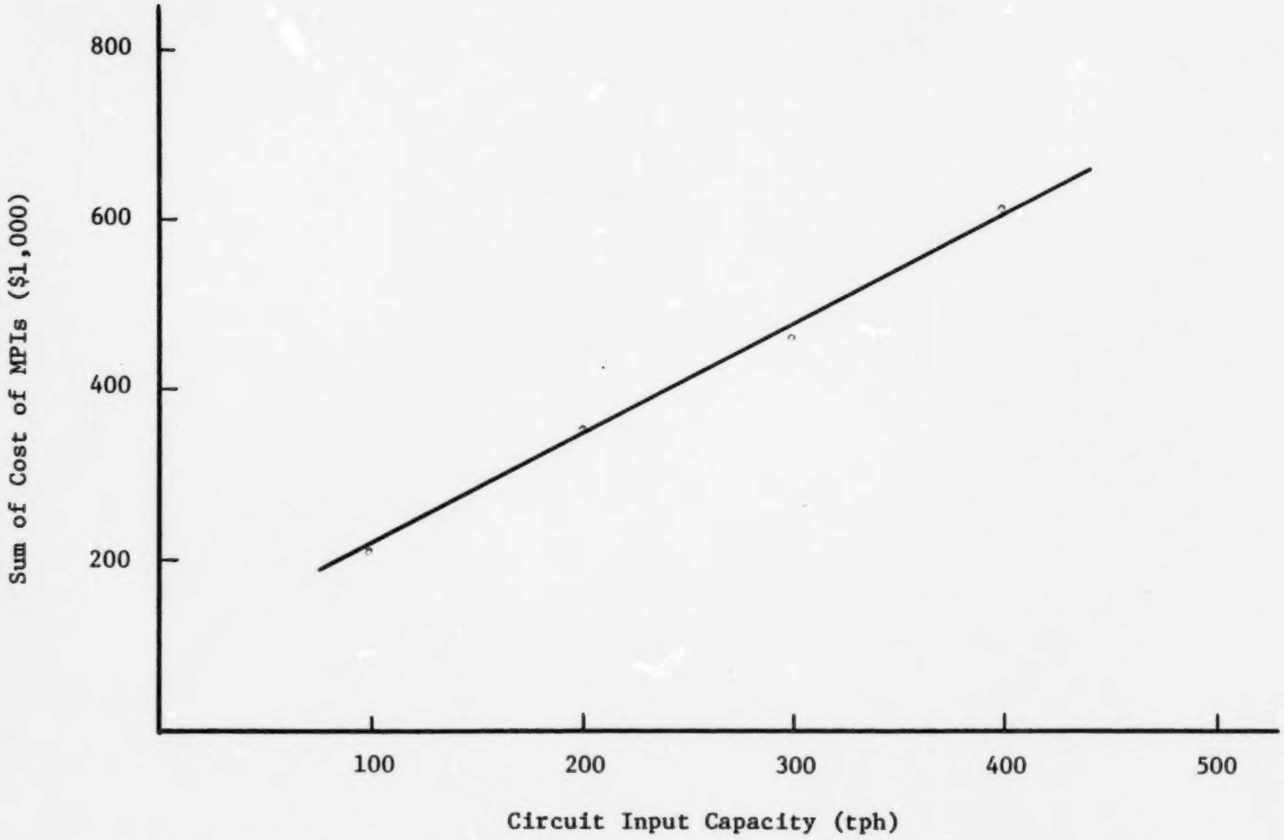
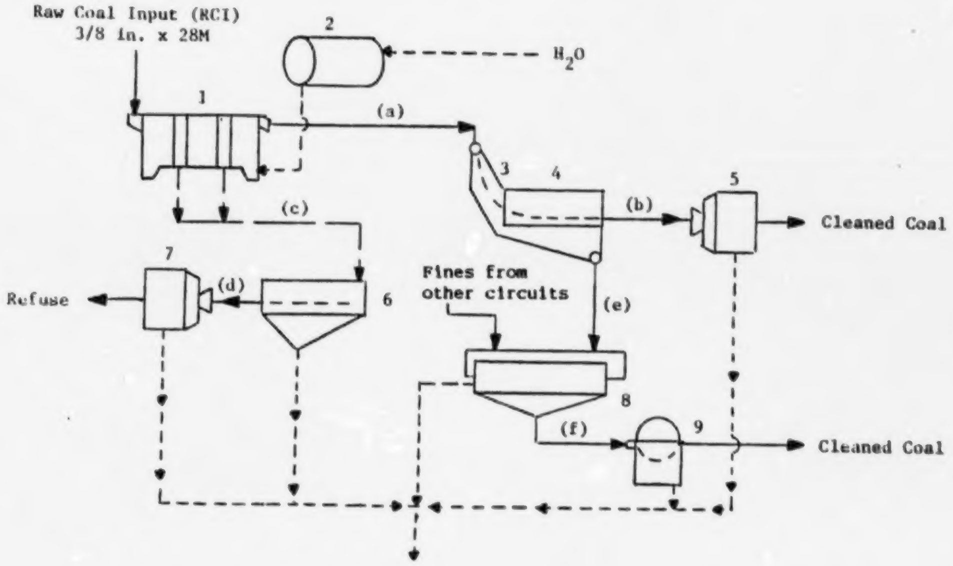


FIGURE 6-14. INTERMEDIATE SIZE COAL CLEANING - HYDROCYCLONES

Intermediate/Fine Size Coal Cleaning - Water Jig--

Fine coal is fed to the (water) jig (Figure 6-15), which provides an effective specific gravity separation by pulsating the water medium. The clean coal from the jig (i.e. float product) is dewatered by sieve bends and screens followed by centrifuges. The underflow from the dewatering sieve bends and screens reports to a thickener. The thickened product is dewatered by a disc filter. The disc filter cake is subsequently combined with cleaned coal. The jig sink product (refuse) is dewatered by screens followed by centrifuges prior to final disposal. The black water resulting from dewatering can be clarified and reused.


Raw Coal Input (RCI)
3/8 in. x 28M
2
H_2O
1
(a)
3
4
5
(b)
Cleaned Coal
(c)
7
Refuse
(d)
6
Fines from other circuits
(e)
8
(f)
9
Cleaned Coal

Sizing Philosophy:
(a) max. 0.95 RCI (b) max. 0.95 RCI (c) max. 0.2 RCI
(d) max. 0.2 RCI (e) max. 0.1 RCI (f) max. 0.1 RCI

FIGURE 6-15. INTERMEDIATE/FINE SIZE COAL CLEANING - WATER JIG

TABLE 6-8. INTERMEDIATE/FINE SIZE COAL CLEANING - WATER JIG (3/8 in. x 28M)

Item No.	Item	100 tph Input	200 tph Input	300 tph Input	400 tph Input
1	Jigs	$780K	$780K	$854K	$900K
2	Head Tanks	Incl. in Jig cost	Incl. in Jig cost	Incl. in Jig cost	Incl. in Jig cost
3	Sieve Bends	2,6'wide $13.8K	4,7'wide $32.4K	6,7'wide $56.7K	9,6'wide $61.9K
4	Coal Screens	2,6'x14' $50.4K	4,7'x14' $117.6K	6,7'x14' $176.4K	9,6'x14' $226.8K
5	Coal Centrifuges	$36K	$94K	$120K	$156K
6	Refuse Screens	1,3'x14' $12.6K	1,6'x14' $25.2K	2,5'x14' $42K	2,6'x14' $50.4K
7	Refuse Centrifuges	$34K	$34K	$36K	$36K
8	Thickeners *	$200K	$200K	$290K	$361K
9	Disc Filters	$130K	$170K	$216K	$306K
	Totals	$1057K, $200K *	$1253K, $200K *	$1501K, $290K *	$1737K, $360K *

* Installed thickener cost

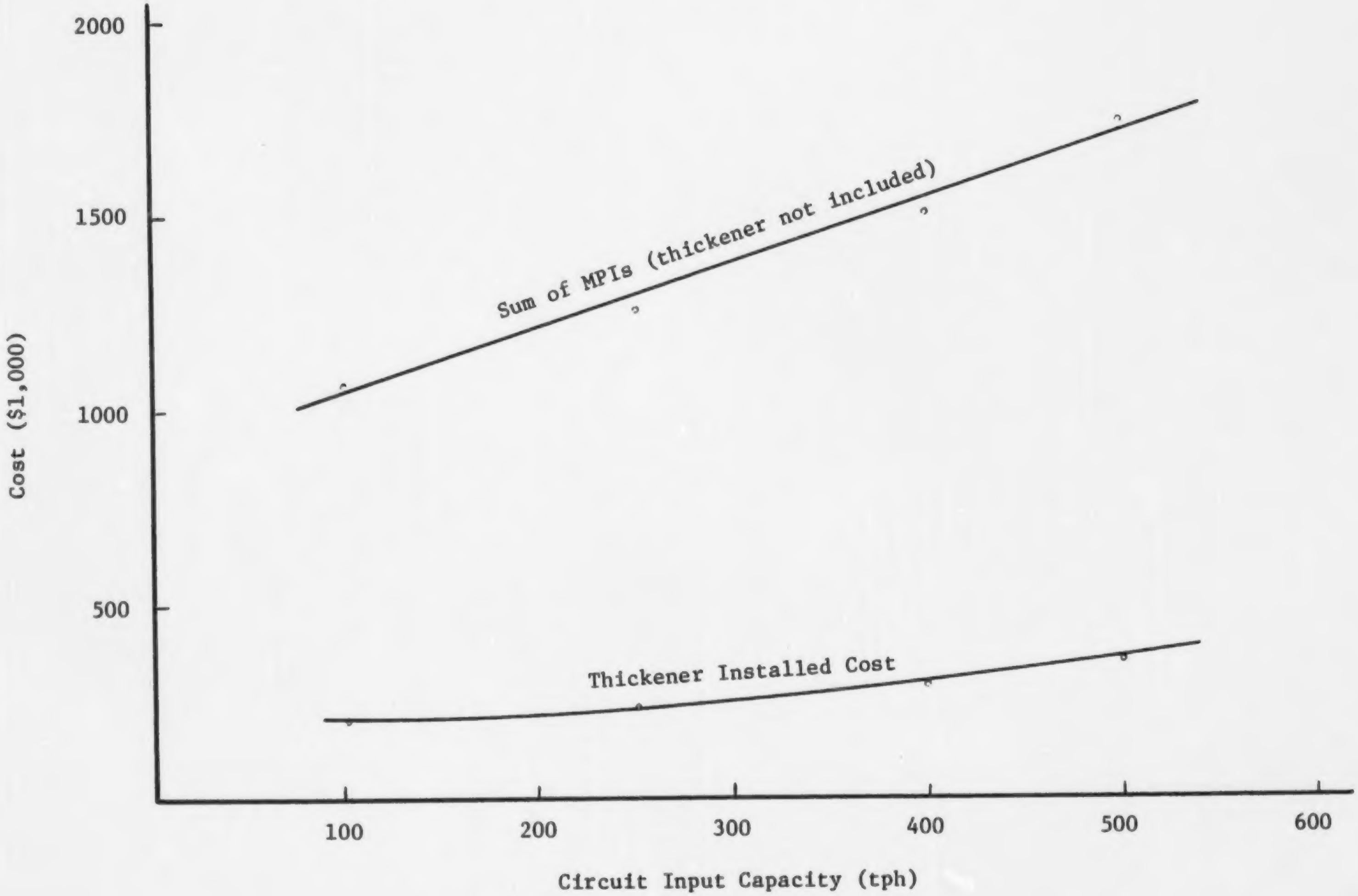
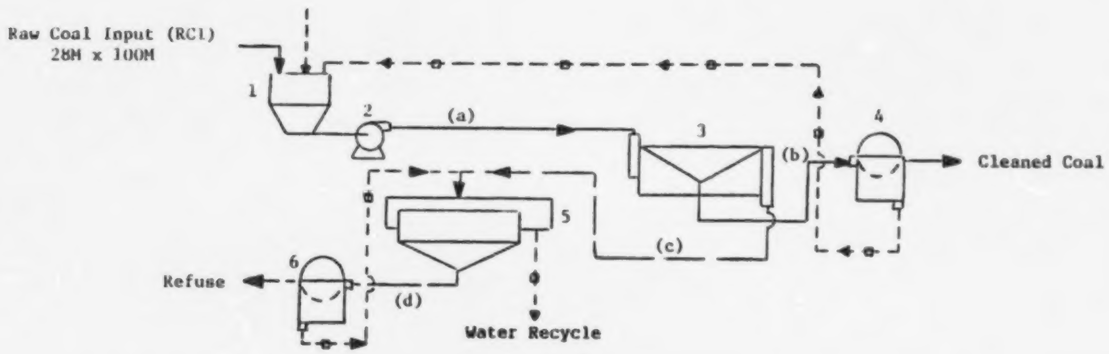


FIGURE 6-16. INTERMEDIATE/FINE SIZE COAL CLEANING - WATER JIG

Fine Size Coal Cleaning - Froth Flotation--

Coal is slurried with water in an input sump and subsequently pumped to the froth flotation cells (Figure 6-17). The cleaned coal product out of the flotation cells is dewatered by a disc filter prior to reporting out. Water from the disc filter is returned to the input sump. The refuse fraction from the froth flotation cells reports to a thickener and the thickened waste product is further dewatered by a disc filter prior to disposal. Reject water from the disc filter is returned to the thickener. The froth flotation cells have an associated automatic level control, a chemical feeder, and a motor.



Sizing Philosophy:
(a) max. 1.0 RCI (b) max. 1.0 RCI
(c) max. 0.2 RCI (d) max. 0.2 RCI

FIGURE 6-17. FINE SIZE COAL CLEANING - FROTH FLOTATION

TABLE 6-9. FINE SIZE COAL CLEANING - FROTH FLOTATION (28M x 100M)

Item No.	Item	10 tph Input	20 tph Input	35 tph Input	50 tph Input	80 tph Input
1	Sumps	$4K	$7K	$9K	$12K	$16K
2	Pumps	$2.5K	$3.2K	$4.5K	$5.4K	$6.8K
3	Froth Flotation Cells	$43K	$54K	$68K	$86K	$134K
4	Disc Filters for Coal	$90K	$130K	$170K	$216K	$300K
5	Thickeners for Refuse *	$55K	$90K	$133K	$170K	$200K
6	Disc Filters for Refuse	$60K	$78K	$100K	$120K	$180K
	Totals	$200K, $55K *	$272K, $90K *	$352K, $133K *	$440K, $170K *	$637K, $200K *

* Installed thickener cost

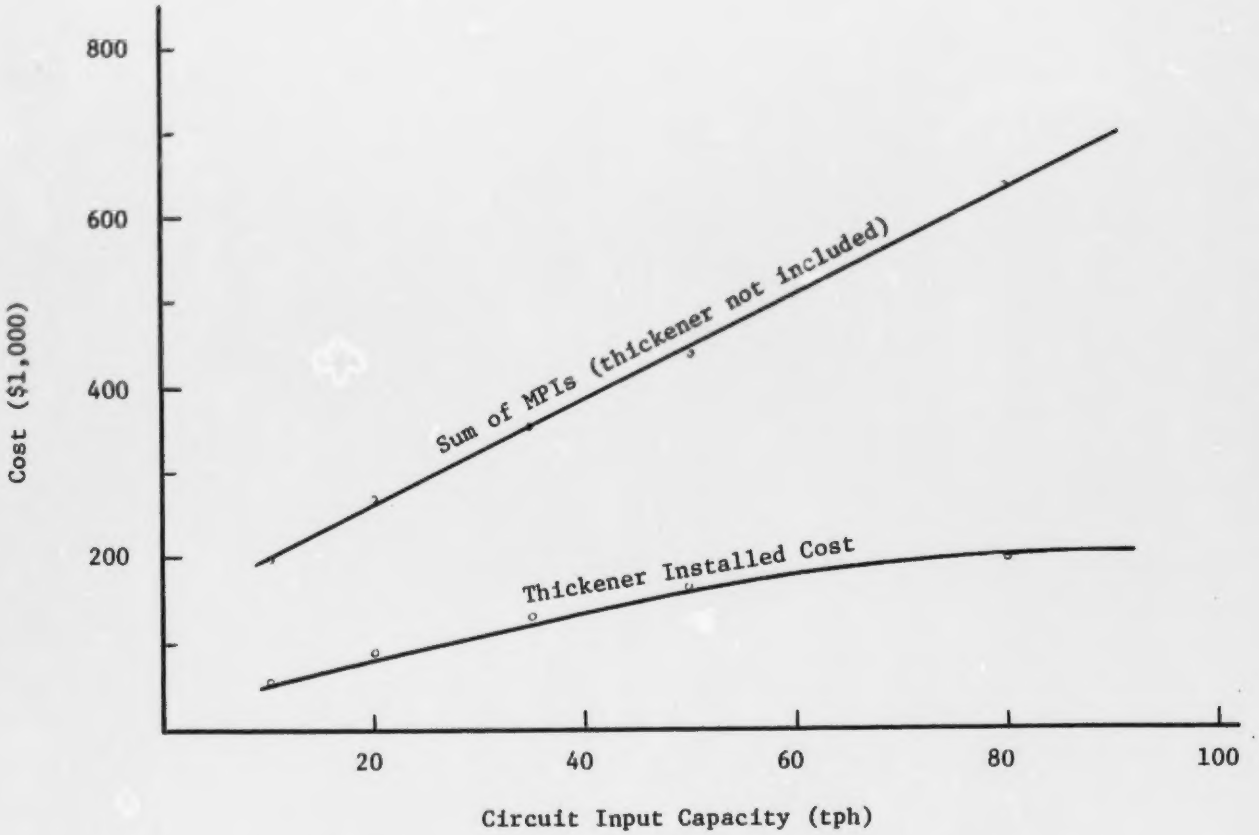


FIGURE 6-18. FINE SIZE COAL CLEANING - FROTH FLOTATION

Heavy Medium Recovery Circuit--

The heavy medium circuit (Figure 6-19) concentrates the cleaning plant collected dilute medium by means of a magnetite separator. The resulting heavy medium is conveyed to the plant's heavy medium circuits. The weak medium out of the magnetite recovery unit (which includes a magnetic separator) is generally used to augment water for wet screening and other washing processes.

The cost of the heavy medium recovery system can be estimated using the following formula:

Cost estimate of components =

$$\$31,000 \times \left[\frac{\text{tph heavy media capacity}}{100}\right]^{0.75}$$

Components

1 Drum magnetite recovery unit with magnetite scrapper
2 Heavy medium sump
3 Pump and driver
4 Heavy medium distribution tank

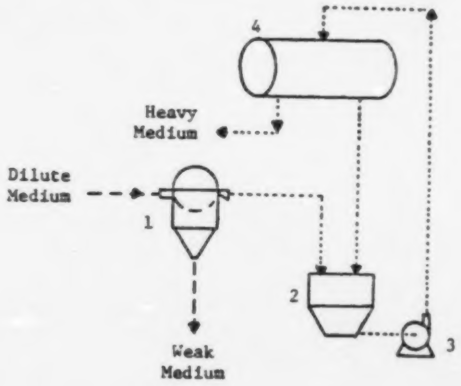


FIGURE 6-19. HEAVY MEDIUM RECOVERY CIRCUIT

Cost of Selected Items Outside of Basic Plant

The total cost of a cleaning facility is composed of the basic (i.e., grassroots) cleaning plant plus items outside of the basic plant. Even though a thickener is located outside of the basic plant structure, it is associated with cleaning plant circuits and therefore the cost of such units is included as part of the basic plant. Since all plants have input and output conveying systems, the cost of conveyors is also included in the cost of the basic plant. Items outside the basic plant structure could include, but are not limited to, the following:

1. Silos and/or bunkers (for coal and refuse)
2. Conveyors (raw coal, clean coal, and refuse belts)
3. Rotary coal breakers
4. Coal stacker
5. Dozers (for coal and refuse control)
6. Thermal dryers

The supplied silo, conveyor, and thickener estimated costs are in terms of contractor installed values. The installed cost values provided below should be multiplied by 1.35 to provide a total cost that includes such items as overall engineering and construction management. Rotary breaker cost estimates are in terms of supplier values and do not include shipping and installation. The total installed cost for rotary breakers is estimated at 3.3 times the equipment cost.

a. Coal Silos (Cast-in-place)

6,000 tons minimum capacity - $125 (estimated) per ton capacity

Less than 5,000 tons capacity - $145 (estimated) per ton capacity

b. Conveyors (Installed Cost)

For conveyors 100 to 500 feet long

Width	Cost per foot	Considered Capacity
30 inches	$672	200 tph
36 inches	$718	400 tph
42 inches	$774	700 tph
48 inches	$830	1000 tph
54 inches	$896	1400 tph

Note: The above costs do not cover exceptional elevation requirements, which can increase the price by as much as a factor of two. The practical loading capacities are influenced by several factors including elevation and length.

c. Rotary Coal Breakers (F.O.B. Price Values)

	4 inch coal pass		
	15 ft. long & 9 ft. diameter	15 ft. long & 11 ft. diameter	18 ft. long & 9 ft. diameter
Base Price	$99,000	$140,000	$108,000
Feed Chute	1,300	2,000	1,300
Refuse Chute	3,400	4,500	3,400
End Liners	6,600	6,600	6,600
Dust Cover	12,500	15,500	14,000
TOTAL PRICE	$122,800	$168,600	$133,300

Definitive estimates of items 4, coal stacker; 5, dozers; and 6, thermal dryers, are not provided. The use of such items is site specific, and the cost variability is sufficiently large that it is best to define needs and obtain budgetary estimates from suppliers for use in plant cost estimates. Order-of-magnitude installed costs for items 4 and 6 may be estimated at $75,000/100 tph for stackers and $2 million/100 tph for thermal dryers.

Coal Cleaning Plant Cost Estimating Work Sheets

Tables 6-10 through 6-12 are cost estimating work sheets. Table 6-10 is used to characterize the circuit capacities and the cost of the associated MPIs. Table 6-11 and 6-12 are then used to calculate the estimated cost of the grassroot plant and the total plant, respectively. The tables are self explanatory.

An illustrative cost estimating example using the work sheets (i.e., Tables 6-10 through 6-12) follows.

TABLE 6-10. CLEANING PLANT CAPITAL COST PRELIMINARY WORK SHEET

Cleaning Size Fractions

Coarse: 1-1/2 inch by 3/8 inch

Medium: 3/8 inch by 28 mesh (3 size fractions);
3/8 inch x 0 (2 size fractions)

Fine: 28 mesh by 0 (3 size fraction plant)

Design Raw Coal Input Circuit Capacity ________tph
Design Coarse Circuit Capacity ________tph
Design Medium Circuit Capacity ________tph
Design Fine Circuit Capacity (if applicable) ________tph

Cost of Raw Coal Circuit MPIs $________
Cost of Coarse Coal Circuit MPIs * $________
Cost of Medium Coal Circuit MPIs * $________
Cost of Fine Coal Circuit MPIs * $________
Cost of Dense Medium Recovery System $________

Sum $________
Cost of Thickeners $________

* Not including thickeners.

TABLE 6-11. ESTIMATE OF COST OF BASIC PLANT

Item No.	Item	Multiplying Factor	Applied to Item No.	Cost of Item
1	Cost of major plant items (MPIs) not including thickeners	1.0	'Sum' from Table 6-10	$______
2	Installed, erected equipment cost	1.60	1	$______
3	Piping	0.40	2	$______
4	Instrumentation	0.15	2	$______
5	Plant structure and site development	0.20	2	$______
6	Auxiliaries (electric, water, ponds, etc.)	0.25	2	$______
7	Delivery cost allowances for MPIs	0.08	1	$______
8	Cost of thickeners	1.0	8	$______
9	Cost of input and output coal handling systems (e.g., conveyors)	1.0	9	$______
10	Others (site development, outside utility lines, etc.)	0.12	(1+8+9)	$______
11	Total cost of Items 2 thru 10			$______
12	Engineering and construction	0.35	11	$______
13	Contingency and contractor's fee	0.20	11	$______
14	Total Plant Cost, Items 11 thru 13			$______

Note: Costs Not Included –

- Cost of money during construction (can be assumed to equal Item 14 x 5/8 x interest/yr (decimal value) x yrs to construct)
- Initial operating supplies and spares (can be assumed to equal 5% of Item 11)
- Unusual site associated items, e.g., RR load facilities.
- Initial working capital requirements

TABLE 6-12. TOTAL ESTIMATED PLANT CAPITAL COST

Estimated grassroots plant cost per Table 6-11	$________
Cost of construction money	$________
Initial operating supplies and spares	$________
Installed cost of plant related components not included in Table 6-11 (e.g., silos, thermal dryers)	$________
TOTAL COST	$________

ILLUSTRATIVE EXAMPLE

The following is a step-by-step example of how to estimate the capital cost of a cleaning plant designed to accept 3 inch topsize coal. The plant circuits which correspond to the generic plant design shown in Figure 6-1 are:

- An input coal sizing circuit with a 600 tph design capacity. The circuit output is a coarse fraction (1-1/2 inch by 3/8 inch), an intermediate size fraction (3/8 inch by 28 mesh), and a fine size fraction (-28 mesh)
- A heavy medium vessel coarse coal circuit with a 400 tph design capacity
- A heavy medium cyclone intermediate coal circuit with a 200 tph design capacity
- A froth flotation fine coal circuit containing a thickener (for refuse). The circuit design capacity is 50 tph

Ancillary equipment includes:

- A 10,000 ton clean coal silo
- A 400 foot, 42" raw coal conveyor
- A 300 foot, 42" clean coal conveyor
- A 300 foot, 30" refuse conveyor

The cost estimate will not include certain coal handling elements (e.g., stacker, dozer).

The cost estimate for the MPIs in the individual circuits are found in the following figures:

- Raw coal sizing circuit -- Figure 6-4
- Coarse coal circuit -- Figure 6-6
- Intermediate coal circuit -- Figure 6-12
- Fine coal circuit and the thickener -- Figure 6-18

The heavy medium recovery system cost is based on the 600 tph heavy medium circuit capacity and is calculated using the cost versus capacity scaling relationship found on page 6-32.

For this example, the cost of money during construction is estimated at 12 percent and the installed cost of the silo is based on $125 per ton capacity.

The cost values from the figures and relationships are inputs to Tables 6-10 through 6-12 as follows:

Illustrative Example

TABLE 6-10. CLEANING PLANT CAPITAL COST PRELIMINARY WORK SHEETS

Cleaning Size Fractions (three sizes)

Coarse:	1-1/2 inch by 3/8 inch
Medium:	3/8 inch by 28 mesh
Fine:	28 mesh by 0

Design Raw Coal Input Circuit Capacity	600 tph
Design Coarse Circuit Capacity (H. M. Vessel)	400 tph
Design Medium Ciruit Capacity (H. M. Cyclone)	200 tph
Design Fine Circuit Capacity (Froth Flotation)	50 tph
Cost of Raw Coal Circuit MPIs	$ 0.79MM
Cost of Coarse Coal Circuit MPIs *	$ 0.37MM
Cost of Medium Coal Circuit MPIs *	$ 0.30MM
Cost of Fine Coal Circuit MPIs *	$ 0.45MM
Cost of Dense Medium Recovery System	$ 0.19MM
Sum (Item 1 of Table 6-11)	$ 2.10MM
Cost of Thickeners (Item 8 of Table 6-11)	$ 0.16MM

* Not including thickeners.

Illustrative Example

TABLE 6-11. ESTIMATE OF COST OF BASIC PLANT

Item No.	Item	Multiplying Factor	Applied to Item No.	Cost of Item
1	Cost of major plant items (MPIs) not including thickeners	1.0	'Sum' from Table 6-10	$ 2.100MM
2	Installed, erected equipment cost	1.60	1	$ 3.360MM
3	Piping	0.40	2	$ 1.344MM
4	Instrumentation	0.15	2	$ 0.504MM
5	Plant structure and site development	0.20	2	$ 0.672MM
6	Auxiliaries (electric, water, ponds, etc.)	0.25	2	$ 0.840MM
7	Delivery cost allowances for MPIs	0.08	1	$ 0.168MM
8	Cost of thickeners	1.0	8	$ 0.160MM
9	Cost of input and output coal handling systems (e.g., conveyors)	1.0	9	$ 0.743MM
10	Others (site development, outside utility lines, etc.)	0.12	(1+8+9)	$ 0.360MM
11	Total cost of Items 2 thru 10			$ 8.151MM
12	Engineering and construction	0.35	11	$ 2.853MM
13	Contingency and contractor's fee	0.20	11	$ 0.571MM
14	Total Plant Cost, Items 11 thru 13			$11.575MM

Note: Costs Not Included -

- Cost of money during construction (can be assumed to equal Item 14 x 5/8 x interest/yr (decimal value) x yrs to construct)
- Initial operating supplies and spares (can be assumed to equal 5% of Item 11)
- Unusual site associated items, e.g., RR load facilities.
- Initial working capital requirements

TABLE 6-12. TOTAL ESTIMATED PLANT CAPITAL COST

Estimated grassroots plant cost per Table 6-11	$11.57 MM
Cost of construction money	$ 1.74 MM
Initial operating supplies and spares	$ 0.58 MM
Installed cost of plant related component not included in Table 6-11 (i.e., silo).	$ 1.25 MM
TOTAL COST	$15.14 MM

OPERATION AND MAINTENANCE COST ESTIMATE

This section provides an assessment of coal cleaning plant operation and maintenance (O&M) costs and a procedure for estimating the O&M cost of a cleaning plant. All costs are provided on a per-ton-of-coal basis. This assumes the plant is generally operated and manned in accordance with the plant design input capacity.

The estimates are based on ten detailed cost estimates obtained from References 1 and 2; information obtained from large coal company, a TVA study, and The Bureau of Labor Statistics; and data from an equipment manufacturer together with an analysis of all available data. In this regard, it should be noted that cleaning plant O&M costs are facility and site specific. This is due to such factors as cleaning plant differences (e.g., thermal dryer), philosophy of plant management, use of union or non-union work force, plant specific environmental considerations, and differences in electrical energy cost. Even so, the provided cost estimating approach closely tracks past collected O&M costs obtained from operators of existing coal preparation facilities.

In assessing coal preparation plant O&M costs, it is important to recognize the following:

- Electricians, mechanics, and others on operating shifts prepare the plant (as possible) for the maintenance shift. Safety considerations call for electricians to always be available to control equipment during operation and maintenance.
- In the mining industry there are no trade unions per se. A worker can work on anything below his pay scale. If more than 50% of a worker's effort is at a given scale, he/she must be paid that scale. If a worker works at a higher scale, he/she must be paid at that scale for work performed.
- Basic contracts per labor force (at a given mine) are based on past practices.

- Operations strive to have a work force in which the ratings of the workers are sufficient to accomplish all required efforts in an efficient and cost effective manner.
- Direct labor and maintenance expenditures can be misleading where facilities contract out for maintenance and other services.

As previously indicated, the costs are based, in part, on the O&M costs associated with ten existing plants. Examples D-1 through D-10 of Appendix D provide flowsheets, personnel loadings, and O&M costs for the ten plants. Examples D-1 through D-8 (of Appendix D) are based on Reference 1 and provide the economics as of the fourth quarter of 1976. Examples D-9 and D-10 (of Appendix D) are based on Reference 2 and indicate the economics as of the fourth quarter of 1979.

Table 6-13 is a compilation of the labor requirements (by shift) for the ten examined plants. This table represents actual employment and does not cover contracted out services. Based on Table 6-13, an estimate of operating personnel requirements is provided (Table 6-14). The number of electricians + mechanics + stationary equipment operators is found to be reasonably defined by a modification of the Wessel relationship, which is often used to relate the number of process plant personnel with a plant's material throughput.

Table 6-15 summarizes the O&M costs (excluding capitalization expense) for the ten examined plants. The totals of the listed cost components are for the period the data was collected, as indicated. The total fuel and energy costs for each plant were subtracted from the total cost. The revised cost was then modified by appropriate Bureau of Labor Statistics hourly labor rate data (Reference 3) to reflect January 1982 conditions. The resulting January 1982 costs per ton of coal were then plotted as a function of circuit input level (Figure 6-20). With the exception of Examples D-5 and D-7, the values are almost linear. Of the two cases that deviate from the trend, Example D-5 represents O&M cost data for a plant that was experiencing operational difficulties and Example D-7 is for a non-union efficient operation where the labor costs (including contracted services) are quite low.

TABLE 6-13

LABOR REQUIREMENTS FOR EXAMINED COAL CLEANING PLANTS
(Not Including Contracted Services)

	Union Classification	Plant Jig Process 600 tph *	Plant Jig Process 1000tph	Plant Jig Process 1000tph	Plant Jig Process 1600tph	Plant H.M. Process 720 tph	Plant H.M. Process 600 tph	Plant H.M. Process 600 tph	Plant H.M. Process 9000tph	Plant H.M. Process 500 tph	Plant H.M. Tables 700tph
Management											
Superintendent/Manager	NU	1	2	1¼	1	2	1½**	1	1½	2	2
Operating Staff - 1st Shift											
Foreman	NU	1	1	1	2	1	1	1	1	1	1
Plant Operator	4	1	1	1	1	1	1	1	1	1	1
Electrician/Mechanic/Welder	4	1	3	4	5	1	3	1	3	1	2
Mobile Equipment Operator	3	2	3	4	5	5	2	2	2	2	4
Stationary Equipment Operator	3		1	1	4	1	2		2	5	3
Raw/Clean Coal Attendant	3										4
Repairman	3					1					
Repairman Helper	2	1	2	1			1	1	1		
Utility Man/Car Dumper/Screenman/Laborer	1	2	3	2	3	3	2	1	3		1
Operating Staff - 2nd Shift		Same	Same Except 2 less electricians 2 less repr. helper	Same	Same Except 1 less electrician 1 less mobile opr. 1 more rail loader	Same	Same	Same	Combined O&M Same Except 2 more elec/mech 1 more repairman	Same Except 2nd Shift has Combined O&M	Same
Maintenance Staff											
Foreman	NU	1	1	1	2	1	1	1			1
Electrician/Mechanic/Welder	4	3	11	4	8	7	4	1			7
Mobile Equipment Operator	3			1		2					
Repairman	3					1	2	3			
Electrician, Mechanic, Repairman Helpers	2				6		2	1			1
Car Dumper/Utility Man	1	1	1	2		1					

---

* Nominal Input to Cleaning Circuits

** Indicates only one-half of one employees time is devoted to cleaning operation

TABLE 6-14. LISTING OF OPERATING LABOR REQUIREMENTS FOR COAL CLEANING PLANTS

Labor Requirements

On a Plant Basis

General Manager	1 up to 500 tph 1-1/2 from 500 to 1000 tph 2 at 1000 tph and greater

On a Plant Working Shift Basis

Foreman	1
Plant Operator	1
Electricians/Mechanics/ Stationary Equipment Operators*	

$$= 0.062\ (1 + \text{no. of cleaning circuits} + \text{no. of thermal dryers})^{1.8} \times (\text{tph})^{0.24}$$

(Round Result to the next whole integer)

Utility Man	1 for up to 600 tph 2 for 600 - 1000 tph 3 for over 1000 tph
Labors	1 for up to 600 tph 2 for 600 - 1000 tph 3 for over 1000 tph
Mobil Equipment Operator	2 up to 300 tph 3 for 300 - 700 tph 4 over 7000 tph

Total Estimated Operating Personnel (not maintenance) is the sum of the above labor categories, based on the number of operating shifts.

---

* This is based on the Wessel relationship (labor vs. capacity) and the labor requirements associated with ten plants covered in Appendix 6B.

TABLE 6-15

SUMMARY OF O&M COSTS FOR EXAMINED CLEANING PLANT ($/Ton of Coal Input)

	Plant Jig Process* 600 tph	Plant Jig Process 1000tph	Plant Jig Process 1000tph	Plant Jig Process 1600tph	Plant H.M. Process 720 tph	Plant H.M. Process 600 tph	Plant H.M. Process 600 tph	Plant H.M. Process 900 tph	Plant H.M. Process 500 tph	Plant H.M. Tables 700 tph
Labor	0.347	0.503	0.482	0.417	0.762	0.737	0.269	0.302	0.513	0.434
Overhead	0.134	0.211	0.180	0.250	0.326	0.366	0.118	0.196	0.205	0.296
Supplies	0.303	0.324	0.538	0.410	1.114	0.411	0.454	0.778	0.575	0.565
Major Maintenance (Including Parts)	0.134	0.321				0.147	0.340		0.511	0.507
Subcontract Services	0.599	0.132	0.076							
Other Expense				0.084				0.087	0.349	0.330
Fuel and Power (Less Dry Fuel)	0.073	0.233	0.170	0.387	0.165	0.334	0.090	0.456	0.457	0.214
Thermal Dryer Fuel		0.094	0.068	0.213		0.233		0.278	0.130	
Total (Year)	1.59(76)	1.82(76)	1.51(76)	1.76(76)	2.37(76)	2.23(76)	1.27(76)	2.10(76)	2.74(79)	2.35(79)
Total Less all Fuel and Power	1.52	1.49	1.27	1.16	2.21	1.66	1.18	1.37	2.15	2.14
Total Less all Fuel and Power Projected to Jan. 81 Value	2.40	2.35	2.01	1.83	3.49	2.62	1.86	2.16	2.56	2.55

---

* Nominal Input (tph) to Cleaning Circuits

A least-squares linear regression on all 10 data points results in the following:

O&M cost/ton ($) = $-0.0006836X + 2.945$

where X = cleaning plant tons per hour input level

A least-squares linear regression on 8 data points (i.e., excluding data from Examples 6B-5 and 6B-7) indicate:

O&M cost/ton ($) = $-0.0007169\ X + 2.928$

The resulting (straight) lines appear in Figure 6-20. Both lines are extremely close together, with the 8 point line indicating a maximum deviation from any of the 8 points of less than 20 cents per ton of coal. The 8 point regression line is recommended for cleaning plant O&M estimating purposes.

The overall O&M cost for a coal cleaning plant includes labor, overhead, supplies, maintenance, contracted services, fuel and power, thermal dryer heat fuel, and miscellaneous expense. All of the above, with the exception of fuel and power and thermal dryer heat fuel, are covered by Figure 6-20.

A coal cleaning plant uses electrical energy to power equipment (e.g., conveyors and pumps), diesel fuel to run mobile equipment, and, as needed, coal to provide heat for a thermal dryer. Electrical energy and diesel fuel requirements (other than for thermal dryer) are based on a TVA study (Reference 4). For three different cleaning plant configurations, Reference 4 indicates an electrical energy requirement of from 2.9 to 5.9 kwh per ton of coal input, with a middle-of-range value of 4.4. kwh per ton of coal. The diesel fuel requirement (Reference 4) ranges from 0.025 to 0.028 gallon per ton of coal input, with a middle-of-range value of 0.0265 gallon per ton of coal.

A commercial fluid bed dryer for 3/4 inch by 0 coal requires 3 kwh of electrical energy and 0.41×10^6 Btu coal fuel per ton of coal throughput.(5) The considered energy costs per ton of coal are based on the following January 1982 (typical) values.

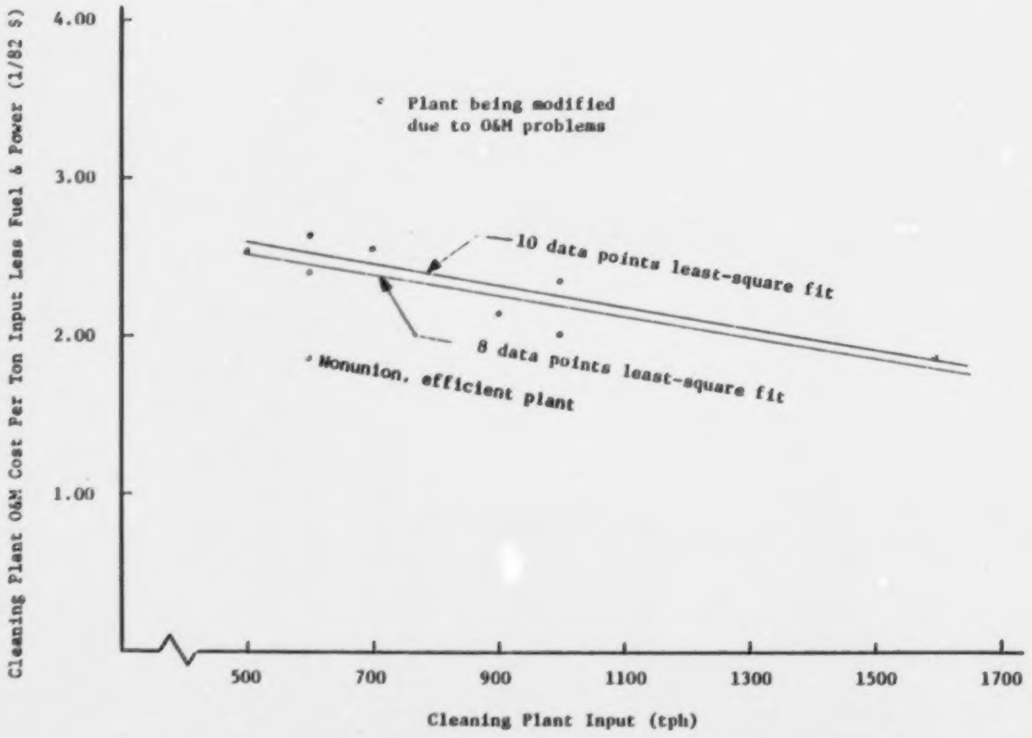


FIGURE 6-20. JANUARY 1982 O&M COST PER TON OF COAL INPUT (not including any energy cost)

TABLE 6-16. ESTIMATED O&M CLEANING COST PER TON OF RAW COAL INPUT TO CLEANING PLANT

Cost (per ton) from Figure 6-20	$________
Electrical Energy Cost (@ 50 mils/kwh)	$0.22
Diesel Fuel Cost (@ $.95/gal.)	$0.03
Thermal Dryer Electrical Energy Cost (@ 50 mils/kwh) .	$0.0015 x % dried
Thermal Dryer Coal Heat Cost (@ $.80/MMBtu)	$0.0033 x % dried
Total	$________

Cost per ton of cleaned coal is equal to the above total value divided by the cleaning plant weight yield expressed as a decimal.

The above does not include amortization of capital cost or coal loss on cleaning

The estimate is the January 1982 value

COST/BENEFIT FACTORS

This section establishes a procedure for identifying, quantifying, and summarizing the relative costs and benefits to a specific utility associated with their selection of alternate sources of coal. Although this technique can be used for evaluating the relative economics of consuming coals from different mines, it can also permit a comparative analysis of firing a single coal in either its raw or cleaned form. Since the focus of this document is the impact of preparation, a raw versus clean coal situation will be used for example purposes.

If all coal were homogeneous, every supplier would be offering a product identical in heat content, ash, sulfur, etc. Under such conditions, coal selection would be solely on the basis of lowest delivered price per ton. However, because coals have widely varying characteristics, they are routinely procured on the basis of lowest delivered price per unit of energy. This has the effect of placing the cost of the commodity in terms of the energy input required by the utility. However, as mentioned previously, procurement exclusively on such a basis does not address a broader range of characteristics which can influence power plant performance and cost. By taking into consideration such factors as relative ash and sulfur contents, decisions among alternative coal supplies can focus on selection providing lower overall cost to the utility. Therefore, although the delivered price per Btu of a given coal may be higher than another, benefits in excess of this price differential can accrue to the utility which has the effect of making it a "better buy."

For illustration purposes, it is assumed that a power plant located in New York State has a coal purchase specification with major elements as follows:

Volatile Matter - 15% maximum
Moisture - 10 % maximum
Ash - 15% maximum
Sulfur - 1.2% minimum to 3.6% maximum
Heat Content - 11,800 Btu/lb minimum
Ash Fusion Temperature - 2,300°F (Reducing-Minimum)
Hardgrove Grindability Index - 55

To respond to this requirement, consideration might be given to using a coal whose principal characteristics in its raw form are as follows:

		Dry Basis	As Received with 5% Moisture
Ash	-	15.01%	14.26%
Sulfur	-	2.62%	2.49%
Heat Content	-	12,775 Btu/lb	12,136 Btu/lb

Although it would appear that this coal in its raw form meets the purchase specification stated earlier, there may be benefits to be derived from firing a higher quality coal. A possible option in this regard could be to clean the coal. By subjecting the coal to a cleaning circuit such as that depicted by Figure D-6 (Appendix D), a clean coal product could be achieved having the following characteristics:

		Dry Basis	As Received with 5% Moisture
Ash	-	6.97%	6.52%
Sulfur	-	2.00%	1.87%
Heat Content	-	14,173 Btu/lb	13,266 Btu/lb

To measure the relative merits of using alternative fuels, a comparative analysis of those areas influenced by coal quality can be performed. For such an analysis, the raw form of this coal will be designated Coal R and the clean form designated Coal C. Further, for illustration purposes it will be assumed the coals can be fired at a new 625 megawatt facility having a heat rate of 8,500 Btu per kilowatt hour. Such a facility would require an annual heat input of 37,187.5 x 10^9 Btu. Through such analysis, estimated values can be developed for the incremental costs in each of those areas associated with consuming alternate fuels. Then, by tabulating these incremental values, a total figure will be established for the "true" or Effective Delivered Cost Per Million Btu. The difference between these figures for any two coals will provide an indication of the overall savings which might be realized by the utility. This savings will be a composite of the incremental differences in the following areas:

1. F.O.B. Mine Coal Cost
    a) Coal Cleaning Plant Operating & Maintenance Cost
    b) Coal Cleaning Plant Capital Amortization
    c) Coal "Lost" during cleaning process
    d) Crushing and Screening Cost
    e) Payment to UMW Trust Funds
2. Transportation Cost
3. Ash Disposal Cost
4. Pulverization Cost
5. Utility Plant Maintenance Cost
6. Emission Control Costs
7. Boiler Availability
8. Boiler Efficiency

F.O.B. Mine Coal Cost

Under the set of circumstances set forth above it is assumed there is a market for this coal in its raw form (Coal R) without physical cleaning. This being the case, it must have an established production cost and selling price. In order to avoid the different rates of return which operators may apply to various aspects of their businesses, this analysis is based on an assumed production cost for Coal R of $20.00 per ton F.O.B. mine. Based upon its as-received heat content of 12,136 Btu/lb, this is equivalent to $0.8240 per 10^6 Btu. The F.O.B. mine (preparation plant) cost of Coal C will be different from that of Coal R as influenced by several factors.

Coal Cleaning Cost. One such factor tending to increase the per unit energy cost will be the cost of cleaning. This includes the operating and maintenance costs related to the cleaning process as well as the amortization of the associated plant capital costs. As presented by Table 6-15, the operating and maintenance cost (1981 dollars) for a cleaning plant such as that depicted by Figure 6-20 is \$2.62 per ton of clean coal. Adding in the cost of fuel and electrical energy (\$0.60 per ton) brings the total O&M cost to \$3.22 per ton of clean coal. The capital amortization cost associated with the assumed coal cleaning facility is \$2.08 per ton of clean coal. Combining these two representative values gives the following cleaning costs:

Cleaning Plant Costs =

Operating & Maintenance + Capital Amortization

Cleaning Plant Cost = 3.22 per ton + 2.08 per ton

Cleaning Plant Cost = 5.30 per ton or $\underline{\$0.200 \text{ per } 10^6 \text{ Btu}}$

Coal Lost During Cleaning. During the cleaning process not all of the thermal energy contained in the raw coal is recovered with the clean product. Some of this energy is discarded with the refuse of cleaning plant reject. Therefore, although the clean coal has a higher unit heat content (i.e., Btu per pound) than the raw coal from which it was produced, more than one ton of raw coal must be mined and processed to yield a ton of clean coal. This potentially saleable energy discarded during the cleaning process has the effect of increasing the cost of Coal C over Coal R on an energy equivalent basis. From the standpoint of the operator, his unit cost increases since he must recover his raw coal production costs over less total saleable units of energy. The actual cost of the heat energy lost can be thought of as the difference between the operators output cost and input cost per million Btu. In the particular cleaning process assumed earlier, 525 tons per hour (tph) of raw coal (Coal R) are fed into the preparation plant and 440 tph of clean coal (Coal C) are recovered. Given the as-received heat content values of the raw feed and clean product assumed at the beginning of this discussion, there is a 91.6 percent Btu recovery associated with this process. Based upon these operating parameters, the input cost of the raw coal to the preparation plant is \$0.8240 per 10^6 Btu (\$20.00 per ton ÷ 24.272 x 10^6 Btu per ton). However, since only 91.6 percent of the energy fed into the preparation process is recovered for sale, the operator experiences an output cost of \$0.8996 per 10^6 Btu (\$0.8240 ÷ .9167). Therefore, the Btu loss will be as follows:

Btu Loss = Output Cost - Input Cost

Btu Loss = \$0.8996/10^6 Btu - \$0.8240/10^6 Btu

Btu Loss = \$0.0756 per 10^6 Btu

Crushing and Screening Cost. A third factor having a bearing on the F.O.B. mine fuel cost is the sizing and screening of the raw coal. When raw coal is not going to be physically cleaned, it is common industry practice to crush and screen to a topsize of approximately 2 inches that coal which is sold to utility plants. The overall cost of this process including coal loading has been estimated by industry personnel to be approximately \$0.90 per ton. When coal is physically cleans, it is not necessary to perform the crushing and screening separately since these functions are now integrated with the overall cleaning process. Therefore, when making a cost comparison between a specific coal in its raw and clean forms, the cost associated with coal cleaning should be reduced by this amount. Based upon the heat content of the raw coal (Coal R), the savings in crushing and screening costs would be as follows:

Savings in Crushing and Screening Costs
= \$0.90 per ton ÷ 24.272 x 10^6 Btu per ton
= \$0.0371 per 10^6 Btu

Payment to UMW Trust Funds. A final factor influencing the F.O.B. mine fuel cost is the amounts paid by the coal operator to the UMW trust funds. Under the terms of the National Bituminous Coal Wage Agreement of

1981, each participating employer must contribute to various pension and benefit trusts on the basis of the tons of coal they produce as well as the hours worked by their employees. The tonnage based portion of these contributions is computed on the basis of cents per ton of coal produced "for use or for sale." Each such ton "produced" carries a burden associated with three separate Trusts totalling $1.59 comprised as follows:

Trust	Period of Coverage	Payment Per Ton
1950 Pension	June 6, 1982 thru Sep. 30, 1984*	$1.11
1950 Benefit	June 6, 1982 through June 6, 1983 (June 7, 1983 thru Sep. 30, 1984* 0.41)	0.40
1974 Pension	June 6, 1982 thru Sep. 30, 1984*	0.08
		$1.59

*Probable termination date of existing Agreement unless otherwise modified.

This burden of $1.59 applies to each ton produced "for use or for sale" regardless of the ash and/or sulfur content of the coal. Since fewer tons of the higher quality coal (Coal C) will be shipped to meet the same energy requirement by the consumer, the operators costs are reduced accordingly. Under the conditions assumed in choosing Coal R or Coal C, 130,500 fewer tons of Coal C would be required to provide the same energy input. Therefore, the operator would pay out $207,495 per year less to the UMW Trust Funds. On the basis of heat content, the potential savings are:

Savings in Payment to UMW Trust Funds =

$$\$207,495 \div 37,187.5 \times 10^{9} \text{ Btu/Year} =$$

$$\underline{\$0.0056 \text{ per } 10^{6} \text{ Btu}}$$

Based upon the foregoing factors directly influencing the F.O.B. mine coal cost, it would be expected that the cost of Coal C on such basis would be $0.2329 per 10^6 Btu higher than Coal R. This was computed by combining the four factors as follows:

	$\$/10^6$ Btu
Cleaning Plan Cost	$0.2000
Btu Loss	0.0756
Crushing and Screening of Raw Coal	(0.0371)
Payment of UMW Funds	(0.0056)
Adjustment to F.O.B. Mine Coal Cost	$0.2329 per 10^6 Btu

Transportation Cost

As in the case of many of the other benefits associated with a higher quality fuel, the potential savings in transportation costs relate directly to the need to bring less material to the power plant to satisfy a certain energy requirement. The magnitude of such savings is a function of the relative heat contents of the alternate coals and the transportation costs. Shipping rates vary widely depending on the mode of transport, route, size of shipment, distance traveled, ownership of equipment, number of carriers, and many other factors unique to the relationship between the carrier(s) and the utility.

Although substantial quantities of coal move via barge and truck, the majority of coal is shipped by rail. For purposes of making a rough estimate of transportation rates, Table 6-17 has been prepared on the basis of sample rates paid by utilities.

Table 6-17

COAL TRAINLOAD RATES EAST OF THE MISSISSIPPI RIVER, ESTIMATED

Rate[a] ($/ton-mile)	DISTANCE TRANSPORTED (miles)
$0.333 to $0.2085	500 to 750
$.0375 to $0.0338	350 to 500
$0.045 to $0.0375	200 to 350
$0.045	LESS THAN 200

---

[a] a/ Based upon Railroad-owned Equipment.

Based upon rail mileage of 430 miles between the source of Coals R and C and the consuming utility (Somerset Plant), interpolation of Table 6-17 indicates a rate of $0.0355 per ton-mile. This would translate to $15.27 per ton of coal shipped. Since 130,500 fewer tons of Coal C would be shipped to supply the required energy input at the power plant, the utility would save $1,992,735 annually in transportation costs. On an energy equivalent basis, the potential savings are:

Transportation Cost Savings = 0.0536 per 10^6 Btu

Ash Disposal Cost

A coal fired utility must dispose of a substantial amount of ash. The total amount of ash is essentially equal to the amount of coal burned times the ash content expressed as a decimal value. Although some utilities have sold collected fly ash for use as a cement ingredient and bottom ash for use as an aggregate, the amount of ash produced by the electric utility industry far exceed the current and potential market for such ash. Excellent progress has been made toward increasing the market potential for this combustion by-product. However, it still remains a cost item for most utilities.

When computing the potential savings in ash disposal cost associated with a higher quality coal, consideration must be given to the fact that the fuel is not only lower in ash, but also higher in heating value, thereby permitting the firing of fewer tons to achieve the same heat input. In order to compute the difference in ash disposal costs associated with Coals R and C, it is first necessary to estimate the amount of ash produced at the power plant when firing each of these two fuels. From this calculation, it is found that there will be 127,093 fewer tons of ash to dispose of when firing Coal C. Using a conservatively low value of $7.00 per ton for ash disposal costs, this amounts to an annual savings of $889,651 when firing Coal C. On the basis of the heat content required by the power plant, this savings are:

Savings in Ash Disposal Cost = 0.0239 per 10^6 Btu

Ash disposal costs are an extremely utility specific variable. This being the case, a rather conservative number of $7.00 per ton of dried ash has been applied in the foregoing calculation. However, as most utilities having coal-fired plants will attest, this has been an area of increasing concern and cost. For example, in a recently released report by the Tennessee Valley Authority and the U.S. EPA, ash disposal costs for a utility starting up in 1984 will range from $26.50 to $32.80 per ton of dried ash, depending upon the type of coal and method used.[6] This general range of values is similar to that quoted in the December 1982, issue of the EPRI Journal. In this article, entitled "Marketing Coal Ash, Slag, and Sludge," the statement is made regarding power plant wastes" . . . may soon cost up to $25 - $40 a ton to dispose of."

Pulverization Cost

There are significant operating costs associated with pulverizing coal and feeding it into a utility boiler. In particular, the pulverizing and air moving equipment consume large amounts of electrical energy. It is currently estimated that it costs $0.80 to pulverize a ton of coal.[7] As the quality of coal consumed by a given power plant improves, fewer tons of fuel will need to be pulverized and fired to provide the required energy input. This being the case, there are savings in pulverizing cost attributable to this higher quality coal.

In computing the potential benefit in this area, it is noted that 130,500 fewer tons of Coal C would be required to provide the necessary energy input. At $0.80 per ton pulverizing costs, this amounts to an annual cost savings of $104,400. On the basis of energy input to the boiler, these savings are:

$$\text{Savings in Pulverization Cost} = \underline{\underline{\$0.0028 \text{ per } 10^6 \text{ Btu}}}$$

Utility Plant Maintenance Cost

Utility plant personnel have always been aware of the inseparable relationship between coal quality and maintenance costs. The difficulty has been in trying to quantify this relationship in a practical manner which can be applied to evaluating alternative fuel choices. Recently, a substantial analytical effort was completed using data from nine of TVA's coal-fired plants over a twenty year period.[8] The relationships (models) developed under that program reflect, with acceptable statistical accuracy, the incremental influence of changes in coal quality on plant maintenance costs. Although other coal quality components are acknowledged to influence maintenance costs, only ash and sulfur were included in these models. Since these models were developed empirically, their application to utility plants outside of the TVA system should be approached with some caution. Further, these models are dependent upon the rated capacity of the facility. Therefore, care should be exercised to insure that the power plant to which the model is being applied is of comparable size to that of the facility from which the model was derived. For purposes of projecting maintenance costs at the previously assumed 625 megawatt facility, a model derived from data at the John Sevier Plant (720 MW) of TVA would be appropriate. This model is composed as follows:

$$\ln \text{Maint } \$(\text{John Sevier Plant}) = 12.59 + 0.00434\,(\text{Ash}) + 0.00955\,(\text{Sulfur})$$

The foregoing model was derived using 1978 dollars. In this model, ash and sulfur are expressed in terms of the thousands of tons entering the boiler at the plant. It is also noted that the maintenance costs are expressed in logarithmic form. This has been done to capture the non-linear relationship between cost and quality. In other words, a one percent increase in ash between 7 and 8 percent would have less of an impact on maintenance cost than a one percent change in ash from 14 to 15 percent.

In assessing the difference in maintenance cost which might be expected from firing Coal C versus Coal R, the estimated annual maintenance cost of each is computed. For Coal R, the following amounts of ash and sulfur enter the plant annually:

Coal R

$$\begin{aligned}\text{Tons of Ash} &= \text{Amount of Coal Fired} \times \text{Ash Percent (decimal value)}\\ &= 1{,}532.1 \times 10^3 \text{ Tons/Year} \times 0.1426\\ &= 218.48 \times 10^3 \text{ Tons of Ash/Year}\end{aligned}$$

Tons of Sulfur = Amount of Coal Fired x Sulfur Percent (decimal)
= 1,532.1 x 10^3 Tons/Yr x 0.0249
= 38.15 x 10^3 Tons of Sulfur/Year

Since under the conditions assumed by this analysis, the consuming utility has approximately the same capacity as the John Sevier Plant, it is appropriate to apply the foregoing model. Entering into the equation the amounts of ash and sulfur experienced when using Coal R yields the following maintenance cost:

ln Maint \$ = 12.59 + 0.00434 (218.48) + 0.00955 (38.15)
ln Maint \$ = 13.9025

Coal R Maint \$ = \$1,090,924 or 0.0293 per 10^6 Btu

For Coal C, the following amounts of ash and sulfur enter the plant annually:

Tons of Ash = 1,401.6 x 10^3 Ton/Year x 0.0652
= 91.38 x 10^3 Tons of Ash/Year

Tons of Sulfur = 1,401.6 x 10^3 Tons/Year x 0.0187
= 26.21 x 10^3 Tons of Sulfur/Year

Applying these values to the maintenance cost model gives -

ln Maint \$ = 12.59 + 0.00434 (91.38) + 0.00955 (26.21)
ln Maint \$ = 13.2369

Coal C Maint \$ = \$560,674 or 0.0151 per 10^6 Btu

To determine the net maintenance cost benefit of consuming Coal C over Coal R -

Maintenance Cost Benefit = 0.0293 per 10^6 Btu - 0.0151 per 10^6 Btu
= 0.0142 per 10^6 Btu

Since the original model was based upon 1978 dollars, this maintenance cost benefit is adjusted to 1981 dollars by multiplying by 1.25 -

Maintenance Cost Benefit = 1.25 x \$0.0142 x 10^6 = \$0.0178 x 10^6 Btu

Utility Boiler Availability

As part of the same analytical effort which developed the foregoing relationship on maintenance costs, the influence of coal quality on boiler availability was also studied in detail. Boiler availability is typically defined as that period during which the boiler is under the control of the operator. Defined in this manner, there are many factors other than coal quality which can influence availability. These include boiler design, age, scheduled maintenance of turbines and other non-coal related areas, load, proficiency of the operators, and a multitude of other factors unique to the particular utility system. In order to exclude these non-coal related influences, a set of data from nine TVA power plants was developed which considered only forced outages and deratings associated with fuel quality as well as selected maintenance outages. These outages were defined to be those caused by the failure of components or equipment coming in direct contact with the coal or the products of combustion.

There are definite costs attributable to forced outages and derating. At the time of their occurance, the generation capacity of the particular unit in question is required by the utility to meet current load demand. In order to replace this capacity, the utility must put into service a less efficient unit and/or purchase a comparable amount of power from another organization. So that this period of "lost" generation capacity could be quantified, a relationship (model) was developed for unplanned outage hours. The most statistically significant model derived for the TVA system as a whole was composed as follows:[8]

$$\ln(\text{Equivalent hours* of unplanned outage annually at TVA plants due to coal related items}) = 3.164 + 0.032\,(\text{Ash}) + 0.293\,(\text{Sulfur}) + 2.176 \ln[2.45 + \arctan[(\text{Age} - 18.8)/8.1]]^{**}$$

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* The term "Equivalent hours" encompasses total plant shut-down as well as reduced load during deratings.

** The term [(Age - 18.8)/8.1] is in radians

Applying the relationship to the assumed plant (new plant, age = 0) under conditions of firing either Coal R or Coal C gives the following unplanned outage hours:

Coal R -

$$\ln(\text{Outage Hours}) = 3.164 + 0.032\,(14.26) + 0.293\,(2.49) + 2.176 \ln[2.45 + \arctan[(0 - 18.8)/8.1]]$$

$$\ln(\text{Outage Hours}) = 3.164 + 0.456 + 0.730 + 0.547 = 4.897$$

$$\text{Outage Hours} = 134$$

Coal C -

$$\ln(\text{Outage Hours}) = 3.164 + 0.032\,(6.52) + 0.293\,(1.87 + 0.547$$

$$\ln(\text{Outage Hours}) = 3.164 + 0.209 + 0.548 + 0.547 = 4.468$$

$$\text{Outage Hours} = 87$$

Therefore, under the conditions assumed, it would be expected that the plant would experience 47 fewer unplanned outage hours when firing Coal C rather than Coal R. It is worth noting that if the plant had been 20 years old, the difference in unplanned outage hours would have been 216, showing the non-linear influence of age.

Once the potential unplanned outage or derating hours under alternate fuel qualities and conditions have been calculated, then the difference can be converted to cost for the purpose of showing the relative benefit of one coal alternative over another.

In some of the previous treatments of this subject, it has been assumed the lost generation during these outages (and deratings) was replaced by a high-cost source such as gas turbines and/or purchased from another utility. Such an assumption is valid during high demand periods when the particular utility does not have lower cost reserve capacity available. However, when such capacity is available, the generation capacity lost by the forced outage or derating of a coal-fired unit will be routinely replaced by putting into service the next most efficient unit. Under these conditions, the cost associated with the lost generation is the difference in incremental operating costs between the disabled unit and the source of the replacement power. Therefore, by taking the difference between the fuel and O&M cost of generation at the unit being analyzed and the annual average cost of replacement power for the whole utility system, an incremental cost per unit of power generation will be determined. Then, multiplying this annual average incremental cost for replacement power by the additional number of outage hours projected when using an inferior quality coal will give the cost of the potentially lost generation.

In the case of the assumed 625 MW coal-fired plant, it was calculated above that 47 fewer unplanned outage hours would be experienced with Coal C. On the basis of an annual average incremental cost for replacement power of 6.82 mills per kilowatt hour (Kwh), every hour the plant is not operating would cost the utility $4,262.50 in increased production costs. Therefore, if 47 fewer unplanned outage hours are experienced during the year, there would be a potential savings of $200,338. Based upon the annual heat input to the plant, the potential savings are:

Boiler Availability Savings = $\underline{\$0.0054 \text{ per } 10^6 \text{ Btu}}$

As stated earlier, this cost is only the differential fuel and O&M expense and does not include an allocation of the capital associated with the generation capacity necessary to provide the replacement power.

Utility Boiler Efficiency

As part of the same analytical effort which developed the foregoing relationships on maintenance costs and boiler availability, the influence of coal quality on boiler efficiency was also studied in detail. Based upon twenty years worth of data from TVA coal-fired plants, it was determined there is statistically significant relationship between boiler efficiency and the ash and moisture contents of the feed coal as well as the age of the unit.[8] It was found that as these factors increased, there was a reduction in boiler efficiency.

The model (equation) felt to be most representative of this relationship within the entire TVA system was composed as follows:

Boiler Efficiency = 91.06 - 0.022 (Ash) - 0.100 (Moisture) - 0.039 (Age)

In this equation, ash and moisture are expressed as a percent of the as-fired coal. By treating ash in this manner, there is no recognition of the actual volume of ash to which the units were exposed over time. This latter factor could influence the extent of deposition within the boiler which would in turn bear on efficiency. Subsequent analysis of boiler efficiency should take this into consideration, possibly as a separate term in the model.

Applying the above relationship to the 625 MW plant under the assumption of firing either Coal R or Coal C gives the following boiler efficiencies:

Coal R -

Boiler Efficiency = 91.06 - 0.022(14.26) - 0.100(5.0) - 0.039(0)
= 91.06 - 0.314 - 0.5 = 90.25 percent

Coal C -

Boiler Efficiency = 91.06 - 0.022(6.52) - 0.100(6.4) - 0.039(0)
= 01.06 - 0.143 - 0.64 = 90.28 percent

Therefore, boiler efficiency will be increased when firing Coal C by the following amount:

Boiler Efficiency Coal C - Boiler Efficiency Coal R =
Improvement in Boiler Efficiency - 90.28 - 90.25 = 0.03 percent

This means that the firing rate would have to be increased by 0.033 percent to maintain the same steam conditions. Therefore, at a delivered cost of \$1.453 per 10^6 Btu (\$0.8240 + 0.629), the saving in boiler efficiency would be:

Boiler Efficiency Savings = \$1.453 x 0.00033 = $\underline{\$0.0005 \text{ per } 10^6 \text{ Btu}}$

In this particular situation, the total influence of changing coal quality on boiler efficiency was insignificant. Although there was a significant change in ash content (14.26 to 6.52 percent), the majority of this positive change was cancelled by the 1.4 percent increase in moisture. As the reader will note from the relative magnitudes of the ash and moisture coefficients in the model, a one percent increase in moisture will cancel a 4.5 percent decrease in ash. This factor should be considered when formulating the coal purchase specification. If moisture had remained unchanged (5 percent) following cleaning, boiler efficiency when firing Coal C would have been projected at 90.42 percent or an increase of 0.17 percent. This would have meant that the firing rate of Coal R would have to be increased by 0.188 percent to maintain the same steam conditions as those when firing Coal C. Therefore, at a delivered price of $1.453 per million Btu, the boiler efficiency savings would have been 0.0027 per million Btu. Although this is a significant improvement over the higher moisture content, it would not of itself justify more extensive drying at the preparation plant.

Emission Control Costs

FGD Associated Costs. Other things being equal, the capital cost of an FGD system is a function of flue gas handling capacity and the flue gas SO_x design level. With lower sulfur coals, it is often possible to meet an SO_x emission standard with less than a full scale FGD system by treating only a portion of the total flue gas. This being the case, the capital cost of an FGD system could be less when using a coal of lower sulfur content. A lower FGD system cost results in a lower capital amortization burden and lower O&M cost.

In addition, when a lower sulfur coal is fired there is a reduction in the sludge disposal requirements. The amount of sludge is essentially proportional to the amount of flue gas cleaned multiplied by the SO_2 concentration of the gas. This assumes comparisons are based on equal FGD SO_2 removal efficiency values.

If one coal has 60 percent as much sulfur as another coal and if only 80 percent as much of the flue gas need be scrubbed for the same boiler Btu input, then approximately 0.8 x 0.6 = 0.48 or 48 percent as much sludge would be generated. In such a case a sludge pond's life is substantially increased and the sludge disposal cost per million Btu boiler heat input is reduced accordingly.

Using the characteristics of Coal R, the following estimated FGD costs would be necessary to comply with a 90 percent removal standard:

	$\$/10^6$ Btu
FGD Capital Cost	0.3795
Flue Gas Reheat Cost	0.0329
Electricity Cost	0.0503
Limestone Cost	0.0308
Maintenance Cost	0.0978
Operating Labor Cost	0.0101
Miscellaneous Cost	0.0041
Coal R Sulfur Emission Control Costs	$0.6055 per 10^6Btu

The foregoing FGD costs were computed using techniques developed in the reference 2 publications. These values could be computed using parts 22 and 23 of the Cost/Benefit Worksheet (Table 6-18) presented later.

Using the characteristics of Coal C, the following estimated FGD costs would be necessary to comply with a 90 percent removal standard:

	$\$/10^6$ Btu
FGD Capital Cost	0.3539
Flue Gas Reheat Cost	0.0329
Electricity Cost	0.0460
Limestone Cost	0.0211
Maintenance Cost	0.0912
Operating Labor Cost	0.0101
Miscellaneous Cost	0.0038
Coal C Sulfur Emission Control Costs	$0.5590 per 10^6Btu

Therefore, the net FGD cost benefit associated with Coal C is -

FGD Cost Benefit = 0.6055 per 10^6 Btu - 0.5590 per 10^6 Btu
= 0.0465 per 10^6 Btu

ESP Associated Costs

Using cleaned coal has a minimal impact on the required ESP collection efficiency. As an example, if 1000 pounds of ash is associated with an amount of coal fed to a boiler, then an ESP collection efficiency of 99.2 percent would limit the ash emission to 8 pounds. If the same coal Btu amount on cleaning has 500 pounds of ash, the same 8 pounds of ash emission limitation would require an ESP efficiency of 98.4 percent. Thus, even with half as much ash, the difference in ESP collection efficiencies is less than 1 percent for the same ash emission value.

However, for a conventional cold ESP the collection efficiency decreases substantially with decreasing coal sulfur contents at levels less than 1 percent sulfur weight. To compensate for this, a substantially more expensive ESP could be employed. However, a potentially more cost-effective approach could be flue gas conditioning that injects minute amounts of SO_3 prior to the ESP. Flue gas conditioning appears to be the most reasonable cost approach with the cost for a 500-700 MWe system estimated to be one million dollars. With flue gas conditioning, the total burden per ton of coal burned probably would not exceed \$0.15 to \$0.18 for a boiler plant with reasonable utilization.

Effective Delivered Cost of Coal

Based upon the incremental cost differences developed in the foregoing subsections, the Effective Delivered Cost per Million Btu of Coal C can be computed as follows:

	$\$/10^6$ Btu
Basic F.O.B. Mine Raw Coal Price	0.8240
Cleaning Plant Cost	0.2000
Btu Loss	0.0756
Crushing and Screening of Raw Coal	(0.0371)
Payment to UMW Funds	(0.0056)
Transportation Cost Savings	(0.0536)
Ash Disposal Cost Savings	(0.0239)
Pulverization Cost Savings	(0.0028)
Maintenance Cost Savings	(0.0178)
Boiler Availability Savings	(0.0054)
Boiler Efficiency Savings	(0.0005)
Emission Control Cost Savings	(0.0465)
Effective Delivered Cost of Coal C	$ 0.9084 per 10^6 Btu

Therefore, if all of the factors influencing costs have been properly computed, Coal R remains a better buy at $0.8240 per million Btu. Even though this cost difference is only $0.0824 per million Btu, it amounts to approximately 3 million dollars annually under the assumed power plant requirements.

The inability of the higher quality alternative (Coal C) to show a cost advantage is principally related to the emission control regulations. By having to comply with a 90 percent removal standard, the FGD capacity necessary for compliance when firing either alternative coal is nearly the same. Therefore, there is very little cost savings attributable to the emission control costs. If this same plant was under a 1.2 pounds of SO_2 per million Btu standard, there would have been FGD cost savings of $0.1239 per 10^6 Btu which would have brought the effective cost of the two coals to within $0.005 per million Btu, making them essentially a "toss-up."

COST/BENEFIT WORKSHEET

In order to simplify the application of this analysis technique, a Cost/Benefit Worksheet has been developed. A sample of this worksheet is presented as Table 6-18. Once the user has provided the basic input parameters under the Power Plant Requirements and Coal Characteristics sections, the incremental costs of all areas influenced by coal quality can be computed without extensive instruction. The final section of the worksheet permits the user to accumulate these incremental values to arrive at the Effective Delivered Price Per Million Btu for each coal option.

To illustrate how this worksheet is used, another power plant location has been identified along with its current operating parameters. Further, two technically acceptable coals have been identified as possible candidates to fulfill the utility's total coal requirements. The specifics of these basic input parameters have been inserted on the sample worksheet, Table 6-18. The reader's attention is drawn to the fact that this second plant is an existing facility operating approximately 5000 hours per year at base load and subject to an emission standard of 1.2 pounds of SO_2 per million Btu.

Table 6-18

COST/BENEFIT ANALYSIS WORKSHEET

POWER PLANT REQUIREMENTS

1. Rated Capacity of Facility 710 Megawatts (MW)
2. Annual Operation at Base Load 5,000 Hours/Year
3. Annual Generation Output $1 \times 2 \div 10^3$ = 3,550 $\times 10^3$ MWH
4. Facility Heat Rate 10,000 Btu/Kilowatt-Hour (KWH)
5. Annual Heat Input Required $3 \times 4 \div 10^3$ = 35,500 $\times 10^9$ Btu
6. Ash Disposal Cost \$ 7.00 /ton of ash

7. Pulverizing Cost $ 0.80 /ton of coal
8. Emission Regulation on Sulfur $1.2\#SO_2/10^6$ Btu
9. Age of Facility 26 Years

COAL OPTIONS AND CHARACTERISTICS

(Provide Coal Quality Information on the basis of as-received values)

10. Characteristics of Coal 1 (Raw Form if applicable)
    a) Heat Content 13,266 Btu/#
    b) Annual Coal Requirement
        5. ÷ [10.a) x 0.002] = 1,338.0 x 10^3 Tons/Year
    c) Ash Content 6.52 percent
    d) Sulfur Content 1.87 percent
    e) Moisture Content 6.4 percent
    f) Rail Mileage From Plant 385 miles
    g) Transportation Rate $0.0366/ton-mile (From Table —)
    h) Unit Transportation Cost = 10.f) x 10.g) = $ 14.09 /ton
    i) F.O.B. Mine Cost $ 25.00 /ton
    j) Incremental F.O.B. Mine Cost
        10.i) ÷ [10.a) x 0.002] = $ 0.9423 /10^6 Btu
11. Characteristics of Coal 2 (Clean Form if applicable)
    a) Heat Content 13,148 Btu/#
    b) Annual Coal Requirement
        5. ÷ [11.a) x 0.002] = 1,350.0 x 10^3 Tons/Year
    c) Ash Content 8.15 percent
    d) Sulfur Content 0.94 percent
    e) Moisture Content 6.1 percent
    f) Rail Mileage From Plant 275 miles
    g) Transportation Rate $0.0413/ton-mile (From Table —)
    h) Unit Transportation Cost = 11.f) x 11.g) = $ 11.36 /ton
    i) F.O.B. Mine Cost $ 25.00 /ton
    j) Incremental F.O.B. Mine Cost
        11.i) ÷ [11.a) x 0.002] = $ 0.9507 /10^6 Btu
        (If raw versus clean insert -0-)

ADJUSTMENT TO F.O.B. MINE COST

(Items 12 thru 15 applicable only if alternatives include raw versus clean form of same coal)

12. Coal Cleaning Cost
    - a) Plant Operating & Maintenance Cost $ — /ton
    - b) Plant Capital Amortization $ — /ton
    - c) Incremental Unit Cost

      12a + 12b ÷ [11a) x 0.002] = $ — $/10^6$ Btu
13. Btu Loss During Cleaning
    - a) Btu Recovery of Cleaning Process — percent
    - b) Incremental Input Cost

      10.i) ÷ [10.a) x 0.002] = $ — $/10^6$ Btu
    - c) Incremental Output Cost

      13.b) ÷ [13.a) ÷ 10^2] = $ — $/10^6$ Btu
    - d) Btu Loss

      13.c) - 13.b) = $ — $/10^6$ Btu
14. Crushing & Screening of Raw Coal
    - a) Crushing & Screening Cost $ — /ton (use $0.90 unless more precise value known)
    - b) Savings in Crushing & Screening Costs

      14.a) ÷ [10.a) x 0.002] = $ — $/10^6$ Btu
15. Payment to UMW Funds
    - a) Difference in Annual Tonnage Requirements

      10.b) - 11.b) = — x 10^3 Tons/Year
    - b) Change in Annual Payment to UMW

      15.a) x $1.59/ton = $ — /Year
    - c) Incremental Change in Payment to UMW

      15.b) ÷ [5. x 10^3] = $ — $/10^6$ Btu

TRANSPORTATION COST SAVINGS

16. a) Incremental Transportation Cost for Coal 1

      10.h) ÷ [10.a) x 0.002] = $ 0.5311 $/10^6$ Btu
    - b) Incremental Transportation Cost For Coal 2

      11.h) ÷ [11.a) x 0.002] = $ 0.4320 $/10^6$ Btu
    - c) Differential Transportation Cost

      16.b) - 16.a) = $(0.0991) $/10^6$ Btu (can be + or -)

ASH DISPOSAL COST

17. a) Annual Ash Disposal Cost For Coal 1

10.b) x [10.c) ÷ 10^2] x 6. = $ 610.7 /10^3/Year

b) Annual Ash Disposal Cost For Coal 2

11.b) x [11.c) ÷ 10^2] x 6. = $ 770.2 x 10^3/Year

c) Differential Ash Disposal Cost

17.b) - 17.a) ÷ 5. = $ 0.0045/10^6 Btu

PULVERIZATION COST

18. a) Internal Cost of Pulverization $ 0.80 /ton (use $0.80 unless more precise value known)

b) Reduction in Annual Pulverization Cost

[11.b) - 10.b)] x 10^3 x 18.a) = $ 9,600 /Year

c) Differential Pulverization Cost

18.b) ÷ [5. x 10^3] = $0.0003 /$10^6$ Btu

MAINTENANCE COST *

19. a) Annual Tons of Ash For Coal 1

10.b) x [10.c) ÷ 10^2] = 87.24 x 10^3 Tons/Year

b) Annual Tons of Sulfur For Coal 1

10.b) x [10.d) ÷ 10^2] = 25.02 x 10^3 Tons/Year

c) Annual Tons of Ash For Coal 2

11.b) x [11.c) ÷ 10^2] = 110.03 x 10^3 Tons/Year

d) Annual Tons of Sulfur For Coal 2

11.b) x [11.d) ÷ 10^2] = 12.69 x 10^3 Tons/Year

e) Projected Annual Maintenance Cost For Coal 1

Take Antilog of:

12.59 + 0.00434 [19.a)] + 0.00955 [19.b)]

= $544,467/Year

f) Projected Annual Maintenance Cost For Coal 2

Take Antilog of:

12.59 + 0.00434 [19.c)] + 0.00955 [19.d)]

= $534,304/Year

---

* Equations in 19 e) and 19 f) valid for units similar to the John Sevier Plant. For unit sizes and ages different from the John Sevier Plant, see reference 3.

g) Differential Maintenance Cost (1978 Dollars)

19.f) − 19.e) ÷ [5. x 10^3] = $(0.0003) 10^6 Btu

h) Differential Maintenance Cost (1981 Dollars)

20.g) x 1.25 = $(0.0004)/$10^6$ Btu

20. a) Projected Annual Unplanned Outage Hours For Coal 1

Take Antilog of:
3.164 + 0.032 [10.c)] + 0.293 [10.d)]
+2.176 ln [2.45 + arc tan [(9. − 18.8)/8.1]]
= 624 Hours/Year

b) Projected Annual Unplanned Outage Hours For Coal 2

Take Antilog of:
3.164 + 0.032 [11.c)] + 0.293 [11.d)]
+ 2.176 ln [2.45 + arc tan [(9. − 18.8)/8.1]]
= 500 Hours/Year

c) Annual Average Incremental Cost for Replacement Power

7.00 mills/Kwh (use 7.00 mill per kilowatt hour unless more precise value known)

d) Differential Boiler Availability Cost

20.b) − 20.a) x [20.c) x 1.] ÷ [5. x 10^3]
=(0.0174)/10^6 Btu

BOILER EFFICIENCY

21. a) Projected Boiler Efficiency For Coal 1

91.06 − 0.022 [10.c)] − 0.100 [10.e)]
− 0.039 [9.] = 89.26 percent

b) Projected Boiler Efficiency For Coal 2

91.06 − 0.022 [11.c)] − 0.100 [11.e)]
−0.039 [9.] = 89.26 percent

c) Delivered Cost of Coal 1

[10.i) + 10.h)] ÷ [10.a) x 0.002]
= $1.4733 /$10^6$ Btu

d) Differential Boiler Efficiency Cost

[21.a) − 21.b)] ÷ [21.a)] x 21.c)
= $ 0 /10^6 Btu

EMISSION CONTROL COST

Coal 1 -

22. a) Unabated Sulfur Emission For Coal 1

$40 \times 10.d) \div [10.a) \times 0.002]$

$=$ 2.82 #$SO_2/10^6$ Btu

b) Scrubber Capacity To Meet Standard

$[1.0 - [8. \div 22.a)] \div 0.9] \times 1. \times 1.15$

$=$ 521 Megawatts

c) Total Scrubber Capital Cost

New Installation

$73.573 \times [22.b) \div 500]^{0.79} \times [[0.098 \times 10.d] + 0.657]$

$= \$$ N/A $\times 10^6$

Retrofit Installation

$91.966 \times [22.b) \div 500]^{0.79} \times [[0.098 \times 10.d)] + 0.657]$

$= \$$ 78.828 $\times 10^6$

d) Incremental FGD Capital Cost

$178.5 \times 22.c) \div [5.] = \$$ 0.4013 $/10^6$ Btu

e) Percentage of Flue Gas Scrubbed

$[22.b) \div 1.] \times 10^2 =$ 73.4 percent

(If 70% or less omit 22.f) - No Reheat Required)

f) Annual Flue Gas Reheat Cost

$[[3.33 \times 22.e)] - 233.33] \times 1. \times 0.0028 \times 2. =$

\$110,254/Year

g) Incremental Flue Gas Reheat Cost

$22.f) \div [5. \times 10^3] = \$$0.0031 $/10^6$ Btu

h) Cost of Electricity 30 mills/Kwh (use 30 mills per kilowatt hour unless more precise value known)

i) FGD Electricity Cost

$0.0004067 \times 22.e) \times 22.h) \div [10.a) \times 0.002]$

$= \$$0.0338$/10^6$ Btu

j) Delivered Cost of Limestone \$ 8.00 ton (use \$8 per ton unless more precise value known)

k) FGD Limestone Cost

$0.000375 \times 10.d) \times 22.e) \times 22.j) \div [10.a) \times 0.002]$

$= \$$0.0155 $/10^6$ Btu

l) Maintenance Cost

46 x 22.c) ÷ [5.] = $ 0.1034 $/10^6$ Btu

m) Operating Labor Cost

For 22.b) < 200 MW:

14,400 x 13 ÷ [5. x 10^3] = $ — $/10^6$ Btu

For 22.b) > 200 MW < 500 MW:

21,600 x 13 ÷ [5. x 10^3] = $ — $/10^6$ Btu

For 22.b) > 500 MW < 800 MW:

28,800 x 13 ÷ [5. x 10^3] = $ 0.0105 $/10^6$ Btu

n) Miscellaneous FGD Cost

[0.10 x 22.e) ÷ [10.a) x 0.2] = $ 0.0028 $/10^6$ Btu

o) Total Incremental FGD Cost For Coal 1

22.d) + g) + i) + k) + l) + m) + n) = $ 0.5704 $/10^6$ Btu

Coal 2 -

23. a) Unabated Sulfur Emission For Coal 2

40 x 11.d) ÷ [11.a) x 0.002] = 1.43 $\#SO_2/10^6$ Btu

b) Scrubber Capacity To Meet Standard

[1.0 - [8. ÷ 23.a)] ÷ 0.9] x 1. x 1.15

= 146 Megawatts

c) Total Scrubber Capital Cost

New Installation

73.573 x $[23.b) \div 500]^{0.79}$ x [[0.098 x 11.d)] + 0.657]

= $ N/A x 10^6

Retrofit Installation

91.966 x $[23.b) \div 500]^{0.79}$ x [[0.098 x 11.d)] + 0.657]

= $ 26.051 x 10^6

d) Incremental FGD Capital Cost

178.5 x 23.c) ÷ [5.] = $ 0.1310 $/10^6$ Btu

e) Percentage of Flue Gas Scrubbed

[23.b) ÷ 1.] x 10^2 = 20.6 percent

(If 70% or less omit 23.f) - No Reheat Required)

f) Annual Flue Gas Reheat Cost

[[3.33 x 23.e)] - 233.33] x 1. x 0.0028 x 2. =

$ -0- /Year

g) Incremental Flue Gas Reheat Cost

$23.f) \div [5. \times 10^3] = \$\ -0-\ /10^6$ Btu

h) Cost of Electricity 30 mills/Kwh (use 30 mills per kilowatt hour unless more precise value known)

i) FGD Electricity Cost

$0.0004067 \times 23.e) \times 22.h) \div [11.a) \times 0.002]$

$= \$0.0096/10^6$ Btu

j) Delivered Cost of Limestone \$8.00 /ton (use \$8 per ton unless more precise value known)

k) FGD Limestone Cost

$0.000375 \times 11.d) \times 23.e) \times 23.j) \div [11.a) \times 0.002]$

$= \$0.0022/10^6$ Btu

l) Maintenance Cost

$46 \times 23.c) \div [5.] = \$0.0338/10^6$ Btu

m) Operating Labor Cost

For 23.b) < 200 MW:

$14{,}400 \times 13 \div [5. \times 10^3] = \$0.0053/10^6$ Btu

For 23.b) > 200 MW < 500 MW:

$21{,}600 \times 13 \div [5. \times 10^3] = \$\ —\ /10^6$ Btu

For 23.b) > 500 MW < 800 MW:

$28{,}800 \times 13 \div [5. \times 10^3] = \$\ —\ /10^6$ Btu

n) Miscellaneous FGD Cost

$[0.10 \times 23.e)] \div [11.a) \times 0.2] = \$0.0008/10^6$ Btu

o) Total Incremental FGD Cost For Coal 2

$23.d) + g) + i) + k) + l) + m) + n) = \$0.1827/10^6$ Btu

24. Differential FGD Cost

$23.o) - 22.o) = \$(0.3877)/10^6$ Btu

TOTAL DIFFERENTIAL COST

	$\$/10^6$ Btu
Basic F.O.B. Mine Cost [Absolute Value of 11j)-10j)]	0.0084
Coal Cleaning cost* [12.c)]	—
Btu Loss* [13.d)]	—
Savings in Crushing & Screening* [14.b)]	(—)
Change in Payment to UMW Funds * [15.c)]	(—)
Differential Transportation Cost [16.c)]	(0.0991)
Differential Ash Disposal Cost [17.c)]	0.0045

Differential Pulverization Cost [18.c)]	0.0003
Differential Maintenance Cost [19.h)]	0.0004
Differential Boiler Availability Cost [20.d)]	(0.0194)
Differential Boiler Efficiency Cost [21.d)]	-0-
Differential FGD Cost [24.]	(0.3877)
Effective Delivered Cost of Coal 2	$(0.4906) per 10^6 Btu

* Apply only to analysis of a specific coal in raw versus clean form.

Since the effective delivered cost of Coal 2 as compared to Coal 1 is a negative value, it indicates that Coal 2 is the preferred choice based upon the assumptions made. These particular coals have very little cost difference on an F.O.B. mine basis. However, when the various transportation, operational, maintenance, emission control, and disposal aspects are considered, there is in fact a significant cost difference. The largest contributor to this difference is the FGD cost.

Using the foregoing procedure, alternate coals can be quickly assessed to determine their relative cost advantage. Because the arithmetic is straight forward and the more significant utility specific variables have been identified, this cost/benefit technique could be easily programmed for use on a microcomputer. Then, multiple combinations of alternate coals could be evaluated by a utility and decisions made concerning how these coals might be appropriately allocated among the plants within their system.

SECTION 6.0

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7.0 ADVANCED COAL CLEANING

Commercial coal preparation technology used today in more than 450 plants has certain limitations and shortcomings. This technology is capable of removing coarse grained mineral matter and pyritic sulfur from coal, but is ineffective for the removal of organic sulfur and most fine-grained mineral matter and pyritic sulfur. For this reason, the maximum amount of ash and sulfur that can be removed by this technology from a given coal is primarily limited by the predominant grain size of coarse grained pyritic sulfur and mineral matter in the coal.

A major shortcoming of the coal preparation technology is associated with the low operating efficiency of the fine coal cleaning equipment used by the industry. Coal cleaning equipment using the separation technique based on the specific gravity differences between coal and its impurities is not effective for particle sizes smaller than 0.5 mm. Froth flotation equipment that employs the principle of surface property differences is somewhat effective for the removal of ash, but cannot always effectively separate pyritic sulfur from coal because of their similar hydrophobic characteristics.

To overcome the limitations and shortcomings of the coal preparation technology, various advanced coal cleaning processes have been developed. These processes can be classified as those that remove sulfur by reaction with a chemical agent, and others that use alternative concepts for improved removal of pyritic sulfur from fine coal.

Various concepts have been proposed and tested to improve pyritic sulfur removal from fine coal. This section discusses various processes and techniques that use four different concepts for the removal of pyritic sulfur. One process uses specific gravity separation in a true heavy liquid medium. Another process separates pyritic sulfur and ash by means of electrostatic forces. The high gradient magnetic separation processes use magnetic forces to remove coal impurities. The oil agglomeration and two-stage flotation processes separate ash and pyrite from coal using the principle of surface property difference.

Processes that remove sulfur by reaction with a chemical agent followed by leaching are called chemical coal cleaning processes. Some of these processes are capable of removing only the pyritic sulfur, and others, both organic and pyritic sulfur. Based on EPA's and DOE's determination of the most promising processes for developmental funding, this section discusses a chemical coal cleaning process that removes both pyritic and organic sulfur by microwave irradiation and sodium hydroxide treatment. Characteristics of other major chemical coal cleaning processes are summarized in Table 7-1.

This section also discusses four other processes that are currently under development. Sulfur removal mechanisms used by these processes include molten alkali leaching, biological oxidation, supercritical solvent extraction, and advanced froth flotation.

MICROWAVE IRRADIATION AND ALKALI LEACHING

A process developed by the General Electric (G.E.) Company removes sulfur from coal by microwave irradiation and sodium hydroxide treatment. The uniqueness of the microwave treatment lies in the fact that the pyritic sulfur and sodium hydroxide can be heated much faster than the coal itself. This treatment results in a rapid reaction of sulfur and sodium hydroxide without significant degradation of coal. Microwave irradiation can be done in one or multiple stages depending on the coal properties and the amount of sulfur to be removed.

TABLE 7-1. MAJOR CHEMICAL COAL CLEANING PROCESSES(1)

Process and Developer	Sulfur Removal Method	Type of Sulfur Removed
"Gravichem,"- TRW Inc.	Gravity separation of feed at a sp. gr. of 1.31; sink is treated with $Fe_2(SO_4)_3$	Above 90% pyritic
"Ledgemont,"- Kennecott/ HRI	1.*Oxidative leachating using O_2 in an acidic solution at 130°C and 10-20 atm. 2.*Oxidative leaching using O_2 in an ammonia solution at 130°C and 10-20 atm.	1.*90 to 95% pyritic 2.*Above 90% pyritic and up to 40% organic
"PETC Oxydesulfurization,"- DOE	Oxidative leaching using air in an acidic solution at 150-200°C and 34-68 atm.	95% pyritic and up to 40% organic
"Ames Wet Oxidation,"- Ames Labs	Oxidative leaching using O_2 in an alkaline solution at 150°C and 14 atm	80 to 90% pyritic and up to 50% organic
"ARCO,"- Atlantic Richfield	Oxidative leaching using O_2 in a solution of an iron-complexing agent at 120°C and 20 atm	Above 88% pyritic
"JPL,"- Jet Propulsion Lab	Chlorinolysis in an organic solvent	Up to 92% pyritic and up to 72% organic (34 to 76% total)
"KVB,"- KVB Inc.	Sulfur is oxidized in NO_2-containing atmosphere. Sulfates are washed out.	60 to above 95% pyritic and 30 to 50% organic
"Battelle Hydrothermal," -Battelle Laboratories	Leaching with a mixed solution of NaOH and $Ca(OH)_2$ at 250-300°C and 39-84 atm	Above 90% pyritic and up to 50% organic
"Magnex,"- Hazen Research, Inc.	Dry pulverized coal treated with $Fe(CO)_5$ causes pyrite to become magnetic. Magnetic materials are removed magnetically.	Up to 92% pyritic

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*The Ledgemont Process has two versions.

Table 7-2 presents examples of irradiation test results on three bituminous coals.(1) These results show that over 80 percent of the sulfur was removed by two-stage microwave irradiation. The increase in the ash content of the bituminous coals after irradiation is due to the sodium deposit on the coal. However, this deposit, along with a major portion of the ash, can be removed by dilute acid wash after the water wash.

In other bench-scale tests,(2) sulfur removal varied from 70 to above 90 percent for bituminous coals containing 1 to 6 percent total sulfur. These results show that the G.E. process is effective for removing not only the pyritic sulfur, but organic sulfur as well.

Later tests by General Electric(3) indicated that microwave irradiation of dry, powdered coal in an inert atmosphere transforms pyrite (FeS_2) to pyrohotite ($Fe_{1-x}S$). The latter can then be easily removed in a weak magnetic field in contrast with the high gradient magnetic fields required for the separation of pyrite from coal. This variation of the G.E. Process has the advantage of being a dry coal cleaning processes, but is restricted to the removal of pyritic sulfur. Currently, research on this variation of the G.E. Process is being conducted in a bench-scale, continuous flow reactor.(4)

A conceptual flow diagram of the G.E. Process is shown in Figure 7-1. Coal is ground to 40 mesh top size and totally wetted with a solution of 20 percent sodium hydroxide. The moist coal is subjected to microwave irradiation for approximately 30 seconds in an inert gas. This irradiation converts sulfur in the coal to sodium sulfide (Na_2S) or polysulfide (Na_2S_x), and evaporates some of the water. Irradiated coal is washed with water to dissolve and remove the sodium sulfides. The slurry is filtered to separate coal from the filtrate. The filter cake is treated by second stage microwave irradiation. The filter cake from this second-stage treatment is dried and finally compacted as the clean coal.

TABLE 7-2. G.E. TEST RESULTS ON THREE BITUMINOUS COALS(1)

Coal Analysis (weight %)	Pittsburgh, PA			#5, Clarion Co., PA		Kentucky # 11, KY	
	Raw Coal	After Single Treatment	After Double Treatment	Raw Coal	After Single Treatment	Raw Coal	After Double Treatment
% TS	2.02*	1.29	0.4	2.37*	0.88	4.18**	0.1
% N	1.21	.24	1.09	1.53	1.49	1.33	1.15
% C	62.25	59.21	53.87	78.82	75.51	60.19	63.34
% H	4.24	3.88	2.22	5.69	5.17	4.80	4.39
% O	10.08	12.36	14.06	9.12	11.44	18.62	22.14
% Ash	19.94	22.02	29.24	2.47	5.53	12.88	8.98
% H_2O	0.7	-	3.0				
% VM	34.74	-	24.7				
%FC	45.32	-	46.10				

Note: Each treatment takes approximately 30 seconds.

* Mostly pyritic sulfur.

** Mostly organic sulfur.

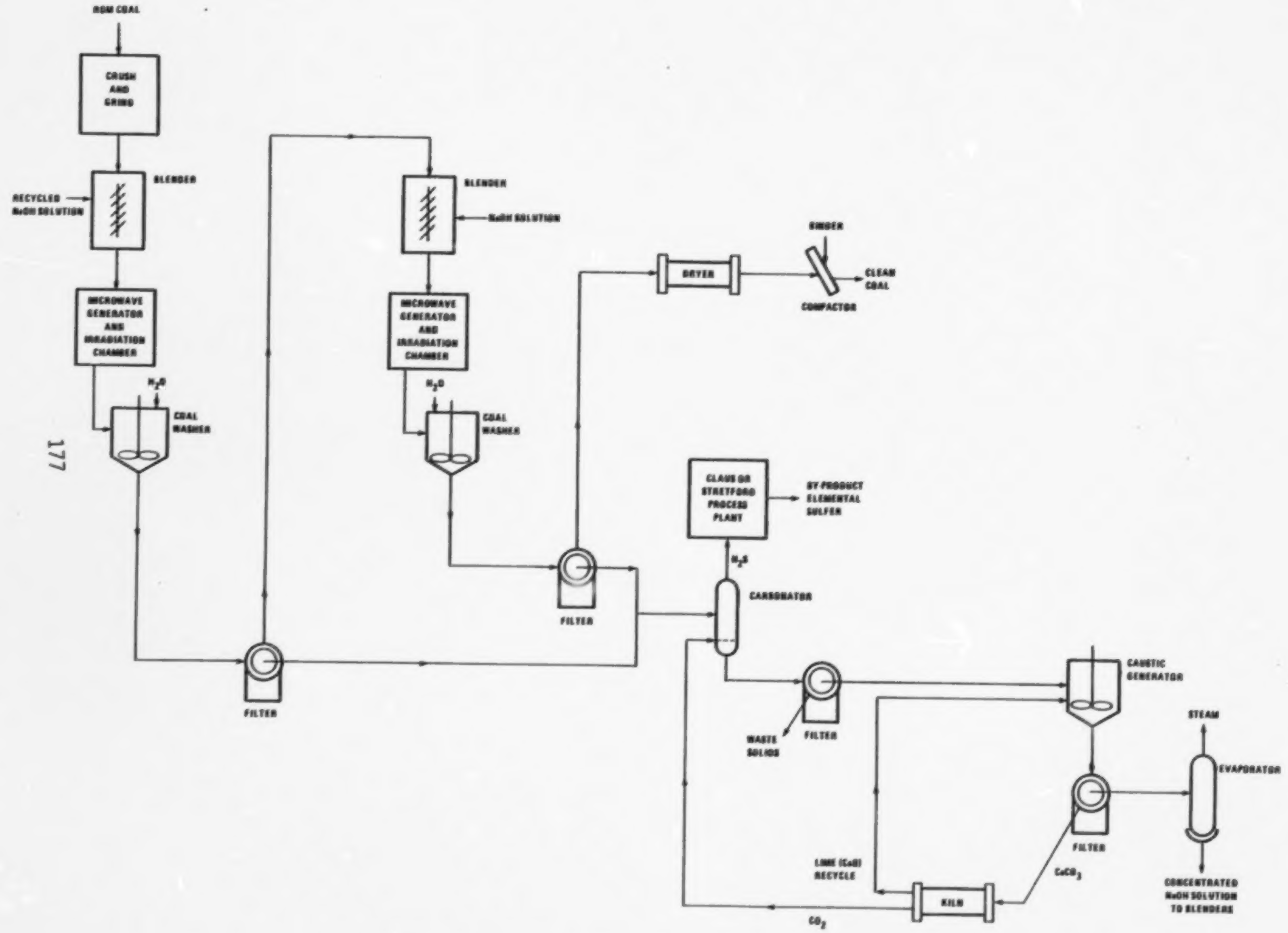
ROM COAL
CRUSH AND GRIND
BLENDER
RECYCLED NaOH SOLUTION
MICROWAVE GENERATOR AND IRRADIATION CHAMBER
H_2O
COAL WASHER
FILTER
BLENDER
NaOH SOLUTION
MICROWAVE GENERATOR AND IRRADIATION CHAMBER
H_2O
COAL WASHER
FILTER
DRYER
BINDER
COMPACTOR
CLEAN COAL
CLAUS OR STRETFORD PROCESS PLANT
BY-PRODUCT ELEMENTAL SULFER
H_2S
CARBONATOR
WASTE SOLIDS
FILTER
CAUSTIC GENERATOR
LIME (CaO) RECYCLE
KILN
CO_2
$CaCO_3$
FILTER
STEAM
EVAPORATOR
CONCENTRATED NaOH SOLUTION TO BLENDERS

FIGURE 7-1. CONCEPTUAL FLOW DIAGRAM OF THE G.E. PROCESS

The filtrates from the first and second stage treatments are sent to a carbonator, where hydrogen sulfide from the solution is stripped with carbon dioxide and converted to elemental sulfur via the Claus Process. The solution from the carbonator containing sodium carbonate is filtered to remove any waste solids, and then reacted with lime to precipitate calcium carbonate and produce a sodium hydroxide solution. The precipitate is first filtered, and then calcined to yield carbon dioxide and lime. The sodium hydroxide solution (filtrate) is concentrated in the evaporator and recycled to the process.

Total capital and annual costs of the G.E. Process are presented in Tables 7-3 and 7-4. The process costs are based on a feed flowrate of 7,200 Mg/day (8,000 tons/day) of coal with a heating value of 28,610 kJ/kg(12,300 Btu/lb). In the cost analysis, the operating factor was taken to be 90.4 percent (330 days/yr), and the process was assumed to have a weight yield and a Btu recovery of 96 percent. The capital cost was estimated to be \$102 x 10^6, and the cleaning cost (excluding the cost of the feed coal) was estimated to be \$15.71/Mg (\$17.30/ton) of product coal.(1) These costs were based on 1977 U.S. dollars. The capital and operating costs are about three to four times higher than those for conventional coal cleaning plants. However, on a cost effectiveness basis (i.e., ¢/lb sulfur removed) the G.E. Process is competitive with modern coal preparation plants. The high weight yield value reflects little or no ash removal by the G.E. Process. Therefore, this process will be most effective on high ash coals when it is used after coal preparation; for low ash coals, it can be used effectively alone.

ELECTROSTATIC SEPARATION

The coal cleaning process developed by Advanced Energy Dynamics, Inc. (AED) uses ionization and electrostatic separation techniques for the removal of ash and pyritic sulfur from pulverized coal in a dry medium. This process can be either incorporated into the design of coal-fired power plants between the pulverizer and the boiler, or used at coal

TABLE 7-3. INSTALLED CAPITAL COST(*) ESTIMATE FOR THE GENERAL ELECTRIC CHEMICAL COAL CLEANING PROCESS(1)
(1977 $)

Coal handling and preparation**	$ 11,284,000
Desulfurization process costs***	
Microwave reactors	29,200,000
Product washing & recovering	19,616,000
Claus process	5,627,000
Evaporators	4,426,000
Compacting and product handling[+]	8,309,000
Building and miscellaneous	---
Utilities (off-sites)	---
Site development and general	---
Subtotal	$ 78,462,000
Engineering Design @ 10%	7,846,000
Contingency @ 20%	15,692,000
Total Installed Plant Capital (TPC)	$102,000,000

---

* All costs are on a fully installed basis.

** Includes storage, sludge pond, railroad sidings.

*** Includes treated coal washing tanks, thickeners, surge tanks, vacuum filters and pumps.

[+] Includes product drying prior to compaction and handling.

TABLE 7-4. ESTIMATED ANNUAL OPERATING COSTS FOR THE GENERAL ELECTRIC CHEMICAL COAL CLEANING PROCESS(1)
(1977 $)

Labor (direct and indirect)	$ 1,830,000
General and administrative (included in labor)	---
Maintenance and supplies	5,310,000
Utilities:	
Electric power	3,100,000
Water	100,000
Steam	4,070,000
Chemicals:	
Sodium hydroxide	4,640,000
Lime	1,220,000
Binder	4,510,000
Waste Disposal	---
Capital Recovery Factor*	11,980,000
Taxes @ 2% TPC	2,040,000
Insurance @ 1% TPC	1,020,000
Total Annual Processing Cost	$ 39,820,000
Raw Coal**	66,000,000
TOTAL ANNUAL COST	$105,820,000

* Assumes equal payment loans for 20 years at 10 percent annual interest rate.

** 2.64 x 10^6 tons (2.39 x 10^6 Mg) at $25.00/ton.

preparation plants. It can also be used to reclaim fine coal refuse. Research on this process is being conducted by AED on a small-scale.

A conceptual design of the AED process is shown in Figure 7-2. Coal pulverized to 70% minus 0.074 mm (200 mesh) is transported in air to the primary cyclone where the ultrafine coal with a top size of 0.020 mm (625 mesh) is removed. The primary cyclone underflow is then transported with the make-up flue gas to the secondary cyclone where the very fine coal (-270 mesh) is separated from the fine coal (+270 mesh). The fine coal is passed first through a silent discharge ionizer and then a baghouse filter to deagglomerate and collect the coal particulates. The collected particulates are introduced into the electrostatic separator to extract pyritic sulfur and ash from coal.

Very fine coal from the secondary cyclone follows the same process steps (i.e., ionizer, filter, and electrostatic separator) as the fine coal in a separate circuit. Cleaned coal from the fine and very fine coal circuits is combined with the ultrafine coal from the primary cyclone and introduced into the boiler for combustion. If desired, the rejects from the electrostatic separator can be reprocessed by another ionizer-filter-electrostatic separator circuit to recover additional coal.

Performance of the AED Process(5) in cleaning 18 run-of-mine coals collected from various locations in the U.S. is shown in Table 7-5. In these tests, (1) the feed coal was pulverized to minus 60 mesh, (2) the two size separations were performed at 60 microns and 270 mesh, respectively, and (3) the refuse from the electrostatic separators was not reprocessed. The results show that the reduction in the SO_2 emission parameter varied between 6 and 49 percent at yields ranging from 63 to 90 percent, and Btu recoveries ranging from 74 to 95 percent. Ash reductions were relatively small (between 7 and 46 percent), and only 3 of the 18 coals were cleaned to a level of 15 percent ash or below. Like the G.E. process, it may be most advantageous to use the AED Process after coal preparation or on coals that do not need much ash removal.

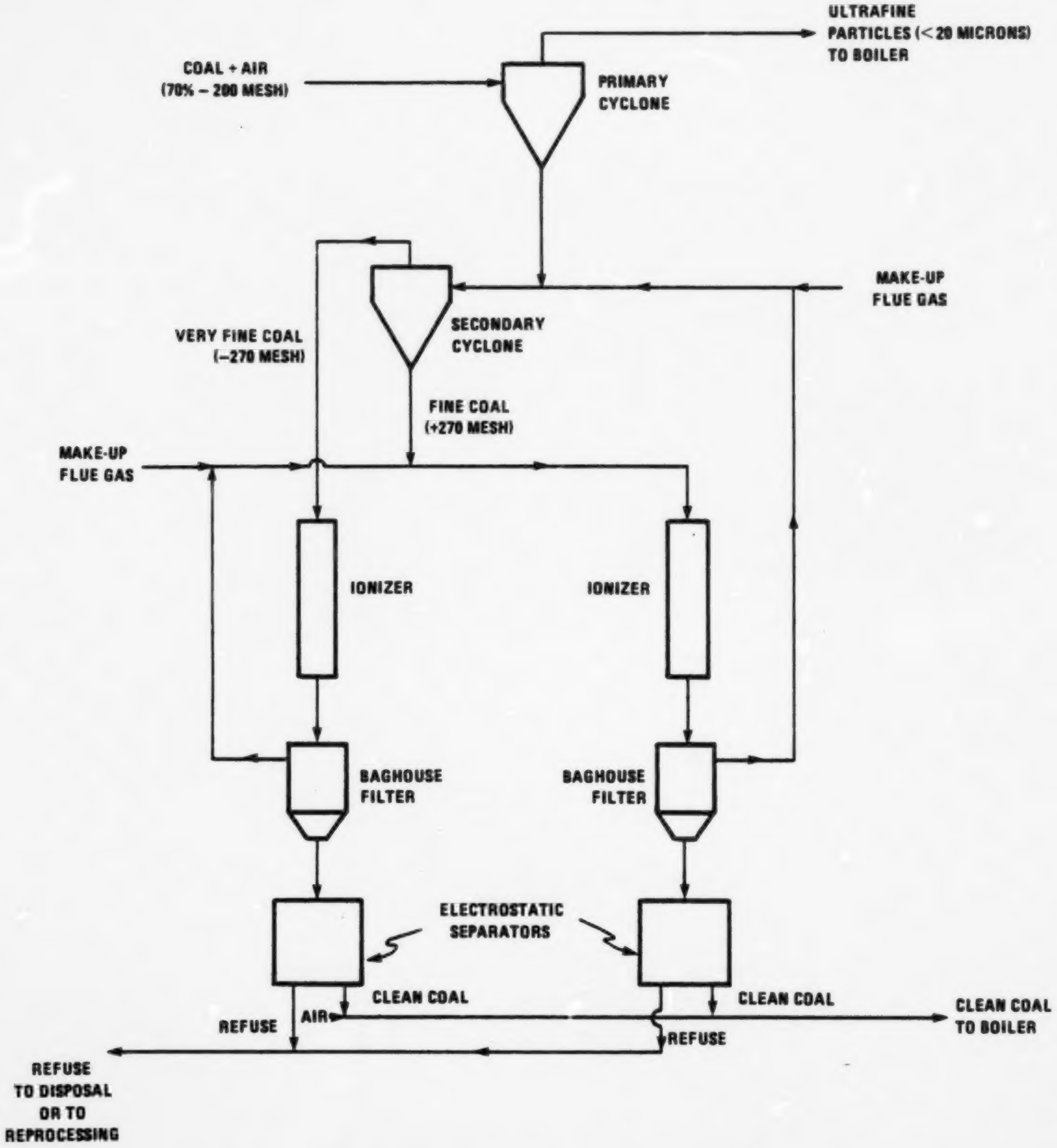
ULTRAFINE PARTICLES (< 20 MICRONS) TO BOILER
COAL + AIR (70% – 200 MESH)
PRIMARY CYCLONE
MAKE-UP FLUE GAS
SECONDARY CYCLONE
VERY FINE COAL (–270 MESH)
FINE COAL (+270 MESH)
MAKE-UP FLUE GAS
IONIZER
IONIZER
BAGHOUSE FILTER
BAGHOUSE FILTER
ELECTROSTATIC SEPARATORS
CLEAN COAL
CLEAN COAL
REFUSE
AIR
REFUSE
CLEAN COAL TO BOILER
REFUSE TO DISPOSAL OR TO REPROCESSING

FIGURE 7-2. CONCEPTUAL FLOW DIAGRAM OF THE AED PROCESS

TABLE 7-5. AED TEST RESULTS.(5)

Coal Seam	State	County	Ash (%)*			Total Sulfur (%)*			Heating Value (Btu/lb)*			SO_2 Emission Parameter (lb $SO_2/10^6$ Btu)				
			Feed	Product	% Reduction	Feed	Product	% Reduction	Feed	Product	% Increase	Feed	Product	% Reduction	% Yield	% Btu Recovery
Undisclosed	PA	Green	32.0	25.6	20	2.24	1.72	23	10,007	11,128	11	4.48	3.10	31	80	89
Lower Kittanning	PA	Armstrong	23.1	21.6	7	3.99	2.89	28	11,541	12,008	4	6.92	4.84	30	90	93
Pittsburgh No. 8	PA	Allegheny	27.8	21.2	24	1.96	1.20	39	10,710	11,790	10	3.66	2.04	44	84	93
Pittsburgh No. 8	WVA	Marshall	38.7	26.9	30	4.02	3.22	20	8,070	10,342	28	9.96	6.22	38	63	81
Pocahontas No. 4	WVA	Mercer	26.3	17.8	32	0.55	0.57	(4)	11,592	12,721	10	0.96	0.90	6	81	89
Jellico	TN	Clairborne	34.1	23.2	32	0.86	0.81	6	9,207	11,034	20	1.86	1.46	22	70	83
Mary Lee	AL	Jefferson	34.3	26.2	24	0.96	0.93	3	9,292	10,898	17	2.06	1.70	17	81	95
Kentucky No. 11	KY	Union	31.0	20.9	33	3.74	3.25	13	8,870	11,021	24	8.44	5.90	30	73	91
Kentucky No. 13	KY	Ohio	18.9	10.3	46	1.42	1.46	(3)	10,511	11,460	9	2.70	2.54	6	83	90
Illinois No. 6	IN	Warrick	22.7	14.9	34	4.15	3.29	18	9,875	11,485	16	8.40	5.90	30	75	87

* Dry Basis
( ) Increase

TABLE 7-5. AED TEST RESULTS.(5) (Continued)

Coal Seam	State	County	Ash (%)* Feed	Ash (%)* Product	Ash (%)* % Reduction	Total Sulfur (%)* Feed	Total Sulfur (%)* Product	Total Sulfur (%)* % Reduction	Heating Value (Btu/lb)* Feed	Heating Value (Btu/lb)* Product	Heating Value (Btu/lb)* % Increase	SO_2 Emission Parameter (lb $SO_2/10^6$ Btu) Feed	SO_2 Emission Parameter (lb $SO_2/10^6$ Btu) Product	SO_2 Emission Parameter (lb $SO_2/10^6$ Btu) % Reduction	% Yield	% Btu Recovery
Illinois No. 3	IN	Clay	24.0	20.2	16	5.57	4.33	22	9,941	10,967	10	11.20	7.90	29	80	89
Illinois No. 6	IL	Franklin	23.3	17.2	26	0.83	0.76	16	10,114	11,475	13	1.64	1.32	20	76	86
Illinois No. 6	IL	Williamson	23.2	14.1	39	3.53	2.60	26	10,528	11,732	11	6.72	4.44	34	80	89
Illinois No. 6	IL	Peoria	35.0	28.8	18	4.14	2.77	33	7,948	9,537	20	10.42	6.04	42	62	74
Illinois No. 5	IL	Knox	39.8	30.2	24	2.93	2.25	23	7,576	8,807	16	7.74	5.12	34	73	85
Illinois No. 2	IL	Fulton	24.2	13.2	45	4.61	3.41	26	9,615	11,096	15	9.58	6.14	36	82	95
Fleming	KS	Bourbon	35.1	24.1	31	4.69	3.72	21	8,981	11,009	23	10.44	6.76	33	71	87
Bee Veer	MO	Randolph	23.3	15.0	36	6.90	3.96	43	10,151	11,526	14	13.60	6.88	49	82	93

* Dry Basis
( ) Increase

TABLE 7-6. TOTAL CAPITAL INVESTMENT FOR THE AED PROCESS
HAVING 117 Mg/h (129 tph) CAPACITY

	COSTS (January 1980 $)		
	MATERIAL	LABOR	TOTAL
Cyclone Separators	135,000	25,100	160,100
Ionizers	200,000	6,200	206,200
Electrostatic Separators	1,506,700	90,000	1,596,700
Blowers and Motors	91,400	18,200	109,600
Lock Hoppers and Surge Bins	448,500	40,600	489,100
Rotary Seal Valves	765,000	28,800	793,800
Bag Filter	150,000	10,000	160,000
Piping, Valves and Fittings	533,800	1,478,100	2,011,900
Modifications to ESS	402,600	-	402,600
Electrical (Power)	279,000	312,000	591,000
Instrumentation and Controls	160,000	102,000	262,000
Structural - Equipment Bldg.	579,000	458,000	1,037,000
Building Heating, Ventilation and Fire Protection	90,000	30,000	120,000
Building Lighting and Misc. Electrical	40,000	25,000	65,000
Total Direct Costs	5,381,000	2,624,000	8,005,000
Total Indirect Costs	1,497,000	1,331,000	2,828,000
Turnkey Cost	6,878,000	3,955,000	10,833,000
Preproduction Costs			368,000
Inventory Capital			90,000
Interest During Construction			325,000
Total Capital Investment			11,616,000

The cost evaluation of the AED Process is available from a study(6) performed by Stone and Webster for AED. The design basis for that study was 117 Mg/h (129 tph) of feed to the process. The turnkey cost and the total capital investment for this process were estimated to be \$10.8 x 10^6 and \$11.6 x 10^6, respectively (Table 7-6). Such capital costs are similar to modern coal preparation plant costs. Annual operating costs are not available.

The process has a total power consumption of 402 kW with the following breakdown for various pieces of equipment:

Ionizers	31 kW
Electrostatic separators	83 kW
Rotary seal valves and lock hoppers	14 kW
Blowers	274 kW
TOTAL	402 kW

HEAVY-LIQUID CLEANING OF FINE COAL

The Otisca Process, developed by Otisca Industries, Ltd., cleans coal from its impurities in a "true" heavy-liquid using specific gravity differences as the separation mechanism. The process has two versions. In the earlier version, referred to as the "Static Bath Process", separation was tested in a static bath; in the more recent version, referred to as the "Heavy Liquid Cyclone Process", coal cleaning is achieved in a cyclone.

In the Static Bath Process, the heavy true liquid was selected to be trichlorofluoromethane. The mechanism of separation in this process can be described by Stokes' Law. This law states that the velocity of separation in a static bath is directly proportional to the square of the particle radius and the specific gravity difference between the particle and the liquid, and inversely proportional to the viscosity of the liquid. According to Stokes' Law, if enough time is allowed in a suitable liquid, a perfect separation of coal from its impurities is expected, except for those very small particles whose motions are dictated by the Brownian forces. The velocity of separation can also be controlled by certain additives. Because static bath separation in a true heavy liquid can handle all feed sizes, this process does not require screening of the feed coal into specific size ranges. The process developer claims from earlier tests that separation is unaffected by the size consist of the feed coal, and is sharp even when processing fine coal.

The static bath separation concept was tested with Upper Freeport seam coal in a 18 Mg/h (20 tph) pilot plant operated by the North Branch Mine of the Island Creek Coal Company at Bayard, West Virginia. The average results(7) from 12 runs at the pilot plant are given in Table 7-7.

TABLE 7-7. AVERAGE OF 12 RUNS AT PILOT PLANT TESTS FOR THE OTISCA PROCESS

	Moisture (%)	Ash (%)	Sulfur (%)	Yield (%)
Raw Coal	5.30 ± 0.4	20.60 ± 1.2	2.70 ± 0.1	73 ± 1
Product	3.60 ± 0.7	9.77 ± 0.6	1.51 ± 0.1	
Reject	6.29 ± 1.2	57.50 ± 3.0	61.4 ± 0.7	

These results show that the coal ash content was reduced by 53 percent and the total sulfur content was lowered by 44 percent at a yield of 73 percent. Following the pilot plant demonstration tests, a full-size (114 Mg/h or 125 tph) Otisca plant was installed at American Electric Power's Muskingum mine near Beverly, Ohio.(8)

Research on heavy liquid cleaning of coal was continued under another program sponsored by DOE. This program, initiated in October 1980, led to the development of a new process that is based on coal cleaning in a cyclone using a true heavy liquid(9). After evaluation of several candidate true heavy liquids, Freon-113 (1,1,2 trichloro 1,2,2 trifluoro ethane) was chosen for the experimental study. This chemical has the following characteristics:

- It permits complete dispersion of coal particles.
- It is non-toxic, non-flammable, non-corrosive, and very stable.
- Its density (1.565 g/cm^3 at 25°C) is suitable for separating coal from coal-ash and pyritic sulfur.
- It has a relatively low boiling temperature (47.6°C at 1 atm) and therefore, can be economically recovered from coal and coal-impurities by evaporation.
- It has a relatively low viscosity (0.68 cp at 25°C), and therefore promotes easy separation of coal from its impurities.
- It does not interact significantly with the coal due to dipole moment or solvation. This result was derived from laboratory tests where the liquid phase viscosity remained almost constant and the resultant slurry viscosity increased with the solids concentration.

Pilot plant tests were performed to demonstrate the cleaning concept in 25.4 mm (1.0 in.) and 50.8 mm (2.0 in.) cyclones using Freon-113 as the separating medium. The selected coal for these tests was from the Upper Freeport seam, Armstrong County, Pennsylvania. Tests performed on 28 M x 0 coal indicated that the performance of the heavy liquid cyclone was far superior than any of any other concepts, commercially available. Near theoretical yields and product quality (ash and sulfur content) were obtained for all incremental size fractions. Further tests were performed on the 0.074 mm x 0 (200 mesh x 0) and 0.037 mm x 0 (400 mesh x 0) size fractions. These tests results are shown in Table 7-8.

A conceptual flow diagram of the heavy-liquid cyclone process is shown in Figure 7-3. Feed coal, with a size distribution of 5 cm x 0 (2 in. x 0), is dry-crushed and ground to 0.595 mm (28 mesh) topsize. The fine coal is then slurried with Freon-113, and the slurry is pumped to the cyclone where clean coal is separated from the refuse. The cyclone overflow, is sent to a thickener, where a large portion of

TABLE 7-8. HEAVY-LIQUID CYCLONE PERFORMANCE SUMMARY

	1	2	3	4	5	6	7
Cyclone Diameter (in)	1	2	2	2	2	1	1
Feed Coal Size Distribution	28M X 0	28M X 0	28M X 0	28M X 0	28M X 0	28M X 0	28M X 0
Wt % Surface Moisture	0	0	20.0	0	0	0	0
Wt % Feed Solids	20.0	20.0	20.0	5.0	20.0	20	20
Clean Coal, Wt % Yield	87.6	87.7	89.3	88.2	86.8	87.9	90.2
Clean Coal, Wt % Ash	5.4	6.0	6.1	5.7	8.6	8.3	8.3
Refuse, Wt % Ash	62.7	61.8	64.4	62.9	65.4	62.2	60.6
Cyclone Pressure Drip, psi	85	85	85	85	25	85	85
Sp. Gr. of Separation	1.61	1.70	1.68	1.68	1.76	1.73	1.80
Probable Error (Ep)	0.009	0.025	0.070	09.020	0.310	0.045	0.100

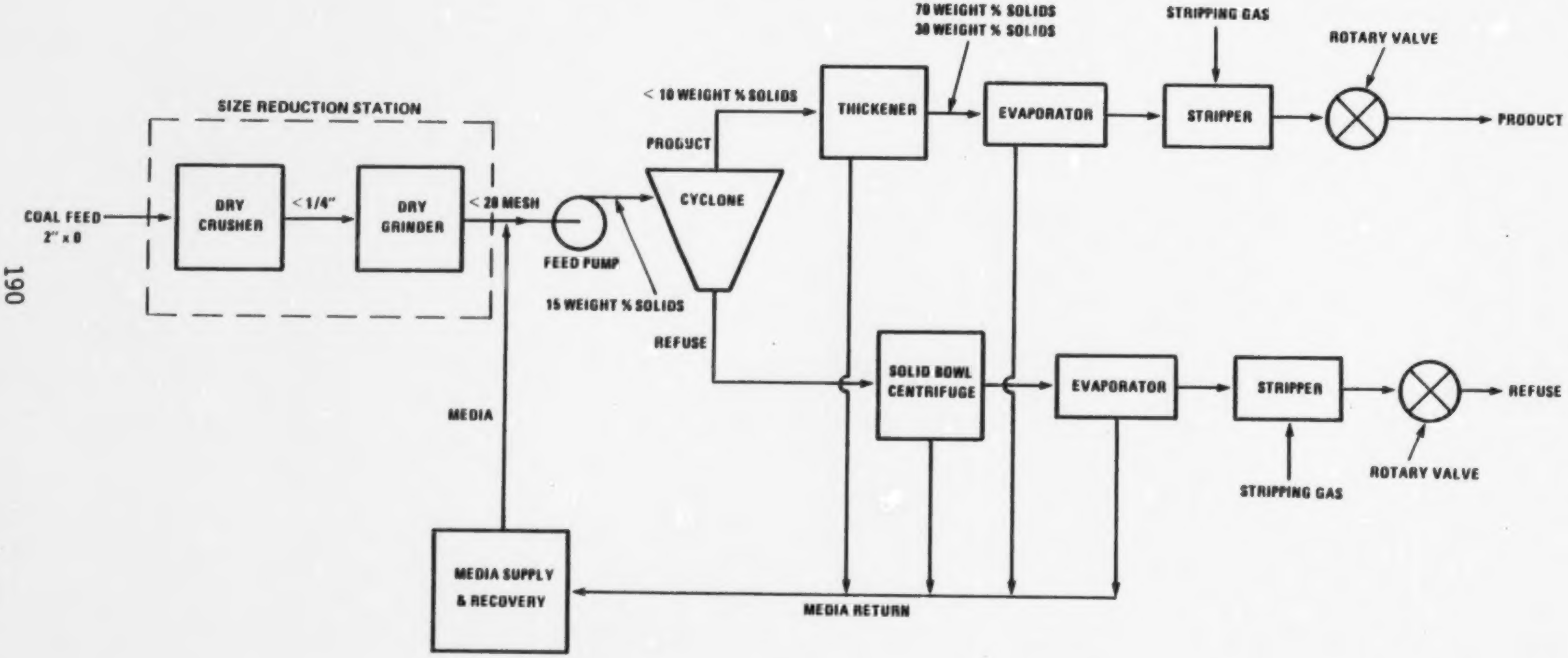
SIZE REDUCTION STATION
COAL FEED
2" x 0
DRY CRUSHER
< 1/4"
DRY GRINDER
< 28 MESH
FEED PUMP
15 WEIGHT % SOLIDS
MEDIA
MEDIA SUPPLY & RECOVERY
CYCLONE
PRODUCT
REFUSE
< 10 WEIGHT % SOLIDS
THICKENER
70 WEIGHT % SOLIDS
30 WEIGHT % SOLIDS
EVAPORATOR
STRIPPING GAS
STRIPPER
ROTARY VALVE
PRODUCT
SOLID BOWL CENTRIFUGE
EVAPORATOR
STRIPPER
STRIPPING GAS
ROTARY VALVE
REFUSE
MEDIA RETURN

FIGURE 7-3. HEAVY-LIQUID CYCLONE CLEANING OF FINE COAL

Freon-113 is removed from the clean coal. Further separation of media from the clean coal is achieved in a series of evaporators and strippers. The clean coal is discharged from the process through a rotary valve. The cyclone underflow is treated in an identical manner except that the refuse is concentrated in a centrifuge. The media recovered from the thickener, centrifuge and evaporators are returned to storage for recycle to the process.

A preliminary economic evaluation of this process was performed by the process developer. The capital cost for a 100 ton plant was estimated to be $7.7 million (1980 U.S. dollars). This estimate does not include costs associated with concentration of the clean coal from the cyclone prior to evaporation. The annualized costs were estimated to be $2.5 million or $7.92/ton of raw coal. The breakdown on the annualized costs is given in Table 7-9.

OIL AGGLOMERATION

Oil agglomeration is a method for separating and upgrading coal particles suspended in a liquid (e.g., water). It involves addition of oil to a coal-water slurry to form an immiscible phase with the water. Under agitation, the carbonaceous components of the coal become wetted and collect in the oil phase as a cluster, (i.e. agglomerate), whereas the inorganic components remain in suspension in the water phase.

Oil agglomeration relies on the surface property differences between coal and its impurities. It is effective for all coal size ranges, including particles finer than 0.074 mm (200 mesh), which cannot be effectively cleaned by means of the flotation technique. Another advantage of oil agglomeration is the low moisture content in the agglomerates. For example, the moisture content of 2 mm (0.07 in.) agglomerates from a dewatering screen is only 10 percent. The reason for the low moisture in the product is two-fold: (1) the agglomerates are coarse products, and (2) oil on coal fines displaces moisture from the

TABLE 7-9. ANNUALIZED COSTS FOR THE OTISCA "HEAVY LIQUID CYCLONE" PRODCESS. (1980 U.S. Dollars).

Operating Costs:			
Operating Labor	256,100		
Maintenance	383,000		
Electricity	734,100		
Process Heat	748,800		
Media	367,100		
Water	1,000		
		$2,490,100	($5.09/ton raw coal)
Fixed Charges:			
Depreciation	383,000		
Return on Investment	574,500		
Supervision	128,400		
G&A (Insur., Txs)	306,400		
		$1,390,300	($2.84/ton raw coal)
		$3,882,400	($7.93/ton raw coal

interior of the agglomerates. The moisture content of coal fines can be reduced to approximately 10 percent by agglomeration followed by screening of 2 mm (0.07 in.) size agglomerates. Therefore, agglomeration eliminates the costly vacuum or thermal drying operations encountered in conventional coal cleaning.

Various oil agglomeration processes have been developed.(10) In the Trent Process, the powdered coal, water, and about 30 percent oil are beaten together to form an amalgam of cleaned coal, the oil passing into or being absorbed by the coal and the ash remaining in the water. By varying the degree and duration of agitation, the amalgam can be made to float or sink, and can be removed mechanically from the water and ash.

In the Convertol Process, 3 to 10 percent oil is mixed with a slurry of coal and water under vigorous agitation, and the product is discharged directly on a high-speed screen centrifuge for dewatering. Unfortunately, this process loses coal where wear causes enlargement of perforations in the centrifuge screen.

In the Spherical Agglomeration Process(11,12) (Figure 7-4) developed by the National Research Council of Canada, agglomeration takes place in two steps. In the first step, light oil is used to separate coal from refuse and to form micro-agglomerates. The micro-agglomerates are then recovered by means of dewatering equipment, such as a sieve bend. If larger agglomerates are needed, the micro-agglomerates are pelletized in the second step with a binder such as asphalt. The resulting pellets are finally dried before shipment of utilization on-site or shipment. The refuse from the micro-agglomeration step is dewatered before it is disposed of. The major drawback of this process is the high costs of oil and binder.

The cost of oil agglomeration can be reduced if agglomeration is integrated with coal preparation. Coarse and intermediate size coal would then be cleaned in conventional coal cleaning equipment (e.g., dense-medium cyclone and concentrating table), and the middling stream

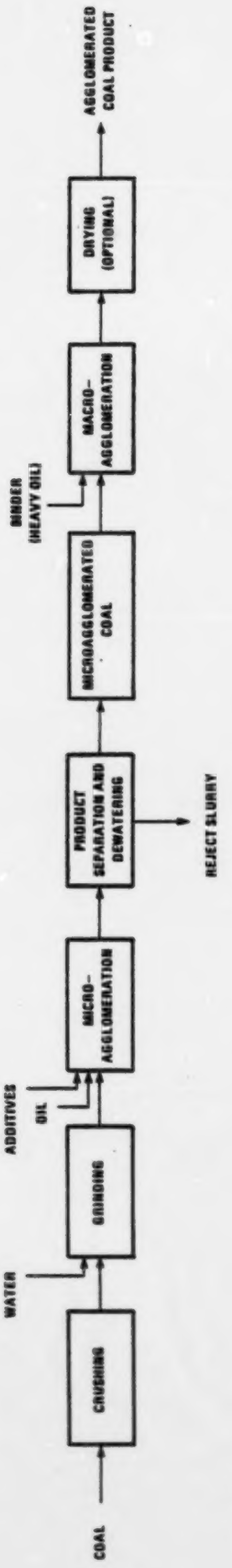
COAL
CRUSHING
WATER
GRINDING
ADDITIVES
OIL
MICRO-AGGLOMERATION
PRODUCT SEPARATION AND DEWATERING
REJECT SLURRY
MICROAGGLOMERATED COAL
BINDER (HEAVY OIL)
MACRO-AGGLOMERATION
DRYING (OPTIONAL)
AGGLOMERATED COAL PRODUCT

FIGURE 7-4. CONCEPTUAL PROCESS BLOCK DIAGRAM FOR THE SPHERICAL AGGLOMERATION PROCESS

from these circuits along with the fine coal would be ground and then treated by the Spherical Agglomeration Process. This integrated process, called the Two-Stage Coal Cleaning Process(11), is shown in Figure 7-5.

The major factors affecting the performance of the oil agglomeration technique include the type of oil and and the conditioning agents added to the coal-water slurry. The type of oil affects the wetting and therefore the recovery of the coal particles. Test results(12) indicate that light oils with specific gravities less than approximately 0.9 (e.g., hexane, coal tar raffinate, Stoddard solvent) can be used for best selectivity of bituminous coals. However, light oils are unable to wet lower rank coals and do not form discrete agglomerates when agitated in a coal-water slurry. The heavier oils, such as coke oven tars, crude oils, and high boiling petroleum components, can be used as conditioning agents for lower rank coals. In addition, chemical agents such as potassium ferrocyanide, sodium carbonate, or iron oxide bacteria, can be added to the slurry to make pyrite particles hydrophilic and to obtain greater pyrite rejections. For example, tests performed on Pennsylvania coals(13) indicated better pyrite and ash rejection in an alkaline solution of sodium carbonate than in water. In addition, oxidative pretreatment of the slurry with air extracted a significant amount of pyritic sulfur from these coals by leaching. Table 7-10 presents some of the oil agglomeration test results with two Pennsylvania coals. Results of tests performed on Iowa coals are also reported in the literature(13).

The solids concentration in the slurry is not a major factor affecting the selectivity of coal particles in oil agglomeration. High recoveries of low ash products can be attained at solids concentrations of 25 percent and oil levels as low as 4 percent.(14)

HIGH GRADIENT MAGNETIC SEPARATION

High gradient magnetic separation (HGMS) is a novel coal cleaning technique that can remove weakly magnetic particles. This technique was first developed in 1969 to upgrade kaolin clay. Successful demonstration

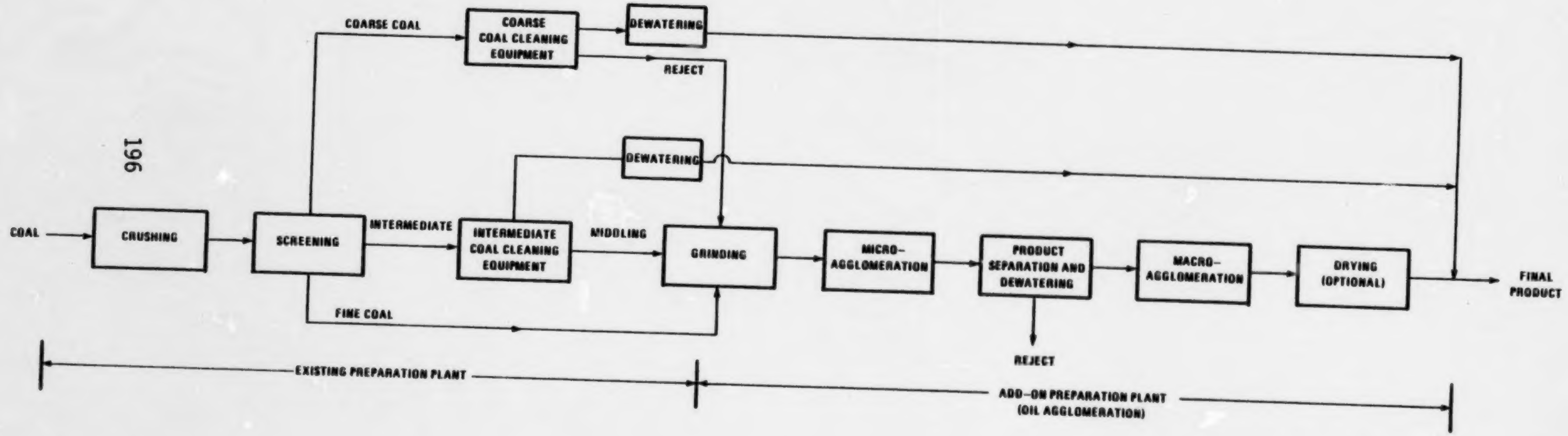
COAL
CRUSHING
SCREENING
COARSE COAL
INTERMEDIATE
FINE COAL
COARSE COAL CLEANING EQUIPMENT
DEWATERING
REJECT
INTERMEDIATE COAL CLEANING EQUIPMENT
DEWATERING
MIDDLING
GRINDING
MICRO-AGGLOMERATION
PRODUCT SEPARATION AND DEWATERING
REJECT
MACRO-AGGLOMERATION
DRYING (OPTIONAL)
FINAL PRODUCT
EXISTING PREPARATION PLANT
ADD-ON PREPARATION PLANT (OIL AGGLOMERATION)

FIGURE 7-5. CONCEPTUAL PROCESS BLOCK DIAGRAM FOR TWO-STAGE COAL CLEANING

TABLE 7-10. COAL YIELD, SULFUR CONTENT, AND PERCENT REDUCTION IN SULFUR CONTENT OF OIL AGGLOMERATED PENNSYLVANIA COALS.[a,b](13)

Treatment	Na_2CO_3 wt%	Yield[c] %	H.V. Btu/lb	Sulfur Content lb/10^6 Btu				SO_2 Emission, Reduction %	
				Pyr.	Sulf.	Org.	Total	Pyr.	Tot.
Upper Freeport Coal									
None[d]	- -	- -	11,180	2.52	0.07	0.57	3.16		
Oil Agglomeration	0	68.8	12,490	1.80	0.11	0.50	2.41	- -	- -
Oil Agglomeration	2	73.4	12,430	1.01	0.23	0.71	1.95	28.6	23.7
Pretreat Only	2	99.7	11,150	1.90	0.21	0.42	2.53	59.5	38.3
Pretrt. & Agglom.	2	68.8	12,810	0.71	0.41	0.73	1.58	24.6	19.9
Pretrt.[e] & Agglom.	2	72.0	12,880	0.57	0.12	0.68	1.37	71.8	50.0
								77.4	56.6
Pittsburgh No. 8 Coal									
None[d]	- -	- -	8,640	3.19	0.16	1.82	5.17		
Oil Agglomeration	0	75.7	12,450	1.43	0.09	1.85	3.37	- -	- -
Oil Agglomeration	2	85.0	12,090	1.11	0.34	2.00	3.45	55.2	34.8
Pretrt. Only	2	100.0	8,670	2.27	0.20	1.73	4.20	65.2	33.3
Pretrt. & Agglom.	2	84.3	12,430	0.70	0.23	2.02	2.95	28.8	18.8
Pretrt.[e] & Agglom.	2	80.0	12,300	0.32	0.17	2.10	2.59	78.1	42.9
								90.0	49.9

[a] Average of duplicate runs except where indicated otherwise.

[b] Feed slurry was prepared by mixing 50 g of 400 mesh x 0 coal with 500 ml water. In oil agglomeration tests, 5 ml of No. 200 LLS fuel oil (Amoco) was added to the slurry.

[c] Coal yield on ash-, oil-, and moisture-free basis.

[d] Heating value and composition of dry, untreated coal.

[e] Pretreated for 1 hr. only one run.

of this technology led to research for beneficiating coal by removing its paramagnetic impurities (i.e., ash and pyritic and sulfate sulfur).

A HGMS unit (Figure 7-6) consists of a solenoidal magnet surrounded by an iron casing. Within the cylindrical volume are fine strands of strongly ferromagnetic packing material such as ferritic stainless steel wool. As high field intensity is generated in this volume, magnetic components (mags) of the feed are captured in the packing material matrix, and the non-magnetic components (tails) are collected at the discharge of the unit. When the matrix becomes saturated with magnetic materials, the feed is stopped, and the magnet is de-energized. The matrix is then backwashed with water to remove and collect the magnetic particles; the unit is thus made ready for use in the subsequent cycle.

To overcome the cyclical mode of operation, a continuous process using a moving matrix HGMS unit, called the Carousel separator, was developed (Figure 7-7). The Carousel separator consists of a rotating ring divided into compartments that contain the matrix of ferromagnetic material. As each compartment enters an elongated solenoid, a slurry is fed into the packing matrix. While the compartment is still within the magnet, it is washed with water to remove any non-magnetic materials adhering to the matrix. As the compartment leaves the magnet, magnetic particles are removed by a second water wash. The largest commercially available HGMS unit has been used for producing high-quality paper coating clays. This unit has been operated at a fixed field intensity of 20 kOe. In coal cleaning, the use of a continuous HGMS unit (instead of a batch unit) is essential to minimize the magnet cycle time required for the removal of mags. It must be noted that the amount of captured material in coal cleaning may easily amount to 30 percent of the feed material.

The HGMS technique was tested wet on various coals including those from the Upper Freeport (PA), Lower Kittanning (PA), Pittsburgh (WVa), Illinois No. 6, Indiana No. 5 and No. 6, and Kentucky No. 9 and 14 seams. The HGMS test results on three of these coals are presented in Table 7-11.(15)

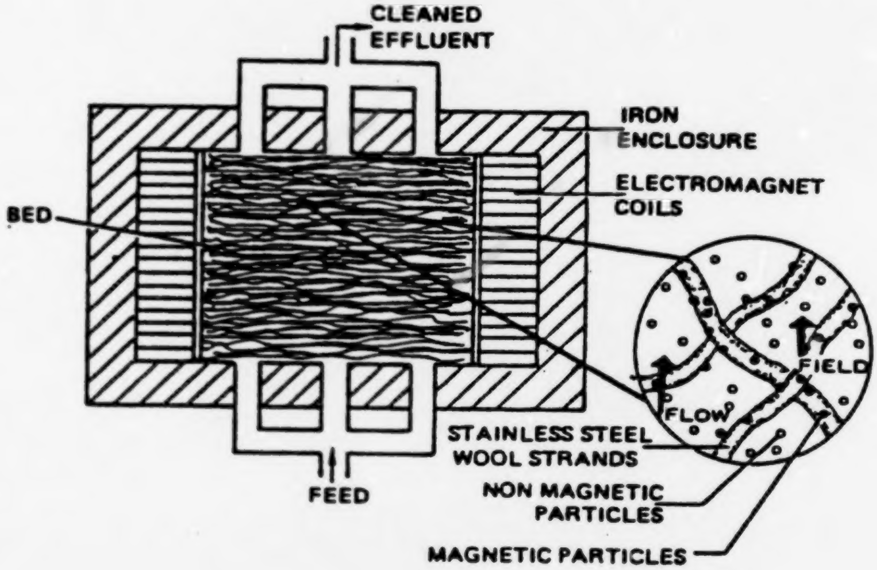
CLEANED
EFFLUENT
IRON
ENCLOSURE
ELECTROMAGNET
COILS
BED
FIELD
FLOW
STAINLESS STEEL
WOOL STRANDS
FEED
NON MAGNETIC
PARTICLES
MAGNETIC PARTICLES

Figure 7-6. High gradient magnetic separator.

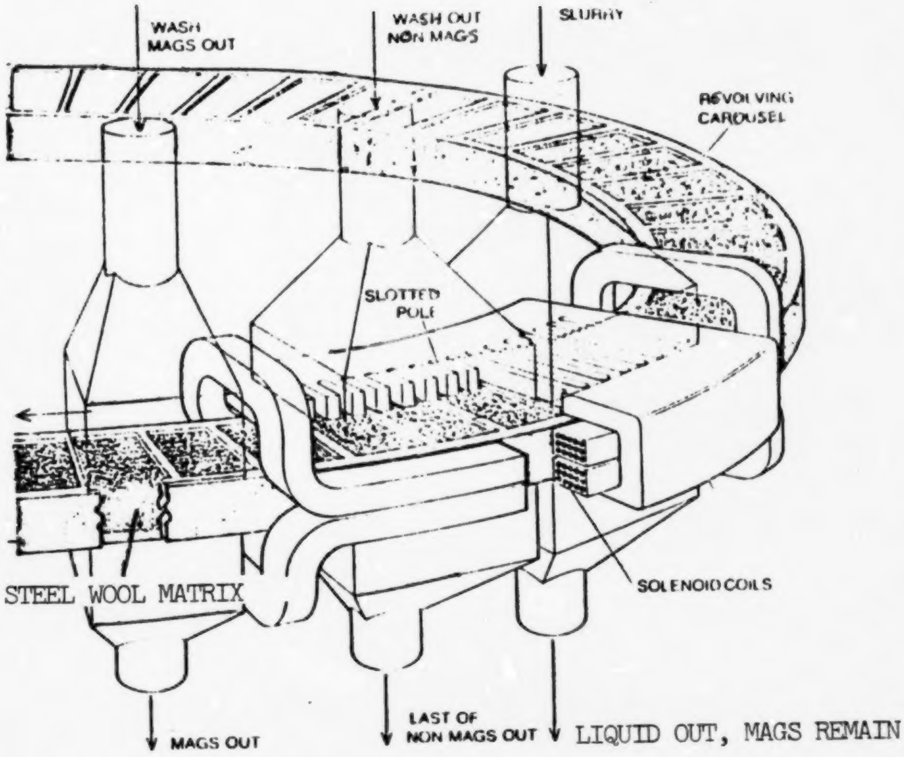
WASH MAGS OUT
WASH OUT NON MAGS
SLURRY
REVOLVING CAROUSEL
SLOTTED POLE
STEEL WOOL MATRIX
SOLENOID COILS
MAGS OUT
LAST OF NON MAGS OUT
LIQUID OUT, MAGS REMAIN

Figure 7- 7. The Carousel separator.

TABLE 7-11. HGMS TEST RESULTS ON THREE COALS(15)

Coal Source			Coal	Pyritic Sulfur	Ash	Yield
Seam	County	State	Top Size	Removal (%)	Removal (%)	(%)
Upper Freeport	Indiana	PA	35 mesh	55-75	59-77	58-75
			100 mesh	65-83	58-77	58-75
Lower Kittanning	Somerset	PA	35 mesh	32-82	32-73	60-80
			100 mesh	55-90	40-77	55-83
Pittsburgh	Marshall	WVa	35 mesh	16-58	16-51	80-95
			100 mesh	35-80	28-61	75-94

Tests performed by DOE on the Upper Freeport seam coal showed that HGMS can remove mineral constituents and pyrite more effectively than flotation. The quality of the recovered coal, although could have been improved by grinding a finer topsize, was far from the optimal as can be predicted from the float-sink analysis.

HGMS research was also conducted under the sponsorship of EPRI. Sala Magnetics Inc. (SALA) performed bench-scale and pilot-scale testing of coal-water slurries using five eastern bituminous coals. Selected results from extensive bench-scale experiments are shown in Table 7-12. These results(16) are associated with runs where maximum pyritic sulfur reductions (and minimum weight recoveries) were achieved. In the pilot-plant test performed on the Upper Freeport coal with the carousel separator total sulfur was reduced by 11 to 40 percent, and ash removal varied between 23 and 51 percent.

Magnetic Corporation of America (MCA) also performed bench-scale coal-water slurry testing on two eastern bituminous coals using a super-conducting HGMS. In these tests magnetic field strengths up to 50

TABLE 7-12. HGMS TESTS RESULTS OBTAINED BY SALA AND MCA.

	Coal Source	Feed T.S. (%)	T.S. Removal(%)	Feed P.S. (%)	P.S. Removal(%)	Feed Ash (%)	Ash Remov[illegible]%)	Wt % Recovery	Btu Recovery
Sala:	Lower Kittanning, PA*	1.94	51	1.20	77	34.8	30	54.4	65
	Sewickley, PA*	2.02	55	1.38	82	33.8	58	37.4	50
	Pittsburgh No. 8, PA*	3.78	33	2.03	66	29.3	28	70.2	ND+
	Upper Freeport, PA*	3.84	65	1.42	62	11.1	60	55.7	61
	Illinois No. 6, IL*	1.87	25	0.81	49	17.7	24	69.2	73
MCA:	Upper Freeport, PA**	1.09	54-57	0.52	86-94	25.7	70-82	14-52	20-70
	Illinois No. 6, IL***	3.33	54	0.93	87-88	15.9	58-79	46-55	53-61

* Feed Size: 50 percent minus 200 mesh, and 90+ percent minus 400 mesh.

** Feed Size: 170 mesh undersize of coal crushed to 76 percent minus 200 mesh.

*** Feed Size: 170 mesh undersize of coal crushed to 82 percent minus 200 mesh.

+ Not determined.

kilogauss were generated. (In the iron-enclosed HGMS used by SALA, a maximum field strength of 20 kilogauss can be generated). These tests results are presented in Table 7-12.(17)

The HGMS technique has also been tested with media other than water such as air, oil, and methanol-water mixtures. Tests with air as a medium showed that a dry HGMS technique is feasible if the ultrafine fraction, which causes agglomeration of particles, is removed before the feed is introduced into the separators by gravity. However, a fluidized-bed HGMS system has successfully demonstrated that ultrafine particle separation is not needed. Fluidized bed HGMS tests performed on the Upper Kittanning seam coal from Pennsylvania showed 47 to 52 percent sulfur reduction at 85 to 92 percent Btu recovery. For the Upper Freeport Seam coal (Pennsylvania), the sulfur reduction was 33 to 38 percent at 82-88 percent Btu recovery. Significant pyrite reductions were also achieved in HGMS tests performed in other media including oil, methanol, and methanol-water mixtures.

A conceptual flow diagram of the wet HGMS process with the SALA separator is shown in Figure 7-8. In this process(18) 5.0 cm x 0 (2.0 in x 0) coal is crushed to 0.118 cm (14 mesh) topsize in cage mills. The crushed coal is wet ground in a ball mill to 70 percent minus 0.074 mm (200 mesh) in a closed circuit. In this circuit, coal from the ball mill is classified in a cyclone: the fine coal becomes the circuit product, and the coarse coal is returned to the mill. The cyclone overflow, because it is too dilute (contains 8 wt. percent solids) to be fed to the HGMS, is concentrated to 30 wt. percent in a thickener with a flocculant. The solids in the slurry are then dispersed by sodium silicate addition and mechanical agitation. The slurry is then introduced into the SALA carousel type HGMS, where clean coal is separated from the refuse. The clean coal that leaves the SALA HGMS, in the form of approximately 20 wt. percent slurry, is dewatered by vacuum filters. The cleaned coal is then thermally dried to produce a product

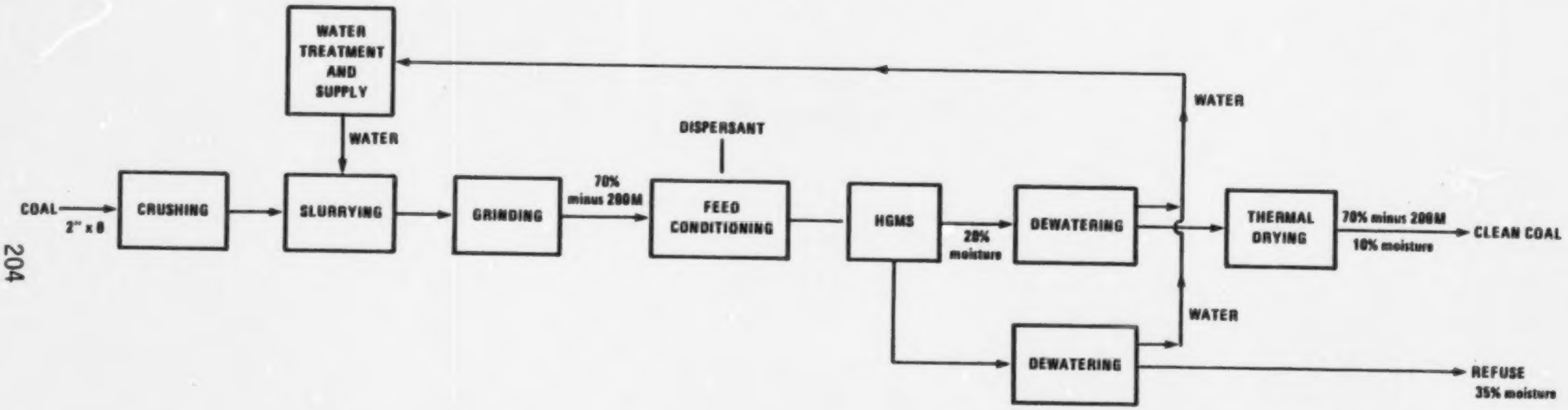
WATER
TREATMENT
AND
SUPPLY
WATER
DISPERSANT
WATER
COAL
2" x 0
CRUSHING
SLURRYING
GRINDING
70%
minus 200M
FEED
CONDITIONING
HGMS
20%
moisture
DEWATERING
THERMAL
DRYING
70% minus 200M
10% moisture
CLEAN COAL
WATER
DEWATERING
REFUSE
35% moisture

FIGURE 7-8. CONCEPTUAL FLOW DIAGRAM OF THE HGMS PROCESS

with 10 percent moisture content. The refuse from the SALA HGMS is thickened in a thickener before disposal. Water from the cleaned coal and refuse dewatering operations is recycled to the process (to the slurry tank).

Capital and annual operation costs for the HGMS technology were estimated based on the conceptual flow diagram shown in Figure 7-8.(18) The design basis included a feed rate of 7,260 Mg/day (8,000 tpd) on an as-received basis, and an operating schedule of 24 h/day and 330 days/year. The feed to the process was assumed to be a 5 cm (2 in.) top size bituminous coal from the Appalachian region with 7 percent moisture content. The weight recovery of the coal was taken to be 81.6 percent on a dry basis, and the product coal from the driers was assumed to contain 10 percent moisture. The capital cost estimate for this process is shown in Table 7-13. The total capital requirements for this process was estimated to be $107.1 million (mid-1978 basis), 56 percent of which is the direct capital costs. The cost estimates also indicate that approximately half of the direct investment is associated with dewatering and drying operations, and the remainder is for comminution and cleaning operations. The annual operating cost estimates for this process are shown in Table 7-14. Fixed and variable operation costs were estimated to be $17 million, and the 30-year levelized total annual operating cost was found to be $51 million. This cost corresponds to $28.20/Mg ($25.61/ton) of clean coal.

Using the same design and cost assumptions, the HGMS process based on the MCA separator was evaluated.(18) Capital, operating, and annualized costs for this process were found to be approximately 10 percent lower than the respective values for the SALA carousel HGMS process. These costs are approximately three times higher than those for a conventional heavy-medium coal cleaning plant with the same annual throughput.

TWO-STAGE FLOTATION

Coal flotation is a technique that is commercially used in coal preparation plants today to remove pyrite and mineral matter from fine

TABLE 7-13. CAPITAL COST ESTIMATES FOR THE SALA HGMS PROCESS(18)
(Mid 1978 Thousand of U.S. Dollars)

	Coal Grinding Operation	HGMS Operation	Clean Coal Filtration and Thermal Drying Operation	Water Treatment Operation	Total Cost	Percent of Total
Direct Costs						
Mechanical Equipment	6,600	11,600	17,700	–	35,900	33.5%
Piping and Instrumentation	1,600	300	7,100	–	9,000	8.4%
Electrical	4,100	1,100	4,800	–	10,000	9.4%
Civil and Architectural	700	1,600	2,200	–	4,500	4.2%
Water Treatment Allowance	–	–	–	1,000	1,000	0.9%
Process and General Facilities Capital Costs	13,000	14,600	31,800	1,000	60,400	56.4%
Percent of Process and General Facilities Capital Costs	21.5%	24.2%	52.6%	1.7%	100.0%	–
Indirect Costs						
Engineering, Home Office Services, and Fees					11,700	10.9%
Spare Parts					800	0.7%
Project Contingency					13,000	13.0%
Process Contingencies					7,500	7.0%
Total Plant Investment					94,300	88.0%
Preproduction Costs					3,300	3.1%
Allowance for Funds During Construction					9,500	8.9%
Total Capital Requirement					107,100	100.0%

TABLE 7-14. ANNUAL OPERATING COST ESTIMATES FOR THE SALA HGMS PROCESS(18) (Mid 1978 U.S. Dollars)

			Annual Cost	Percent of Annual Cost
Fixed Operating Costs				
Labor	Annual Requirement	Unit Cost		
Supervision	16,640 hr	$10.04/hr	$ 167,100	1.0%
Operating	85,280 hr	$ 8.11/hr	691,800	4.1%
Maintenance	39,520 hr	$ 8.22/hr	325,000	1.9%
Subtotal, Labor	141,440 hr	$ 8.37/hr	$ 1,183,900	7.0%
Direct Payroll Overhead – 35% of Direct Labor			$ 414,400	2.4%
General and Administrative Expenses – 60% of Direct Labor			$ 710,300	4.2%
Maintenance Materials/Contracts			$ 1,343,000	7.9%
Subtotal, Fixed Operating Costs			$ 3,651,600	21.5%
Variable Operating Costs				
Utilities	Annual Requirement	Unit Cost		
Electricity	163.7×10^6 kWh/yr	$0.04/kWh	$ 6,548,000	38.6%
Clean Coal	74,448 tons/yr	$26.40/ton	1,965,400	11.6%
Water Treatment	$4{,}140 \times 10^6$ gal/yr	$0.20/1,000 gal	828,000	4.9%
Subtotal, Utilities			$ 9,341,400	55.1%
Solid Refuse Disposal	366,696 tons/yr	$8.50/ton	$ 3,116,900	18.4%
Materials and Supplies	Major Commodities			
Operating Supplies				
	Ball Charge, Filter Cloth		$ 175,000	1.0%
Chemicals	Flocculant, Sodium Silicate		685,000	4.0%
Subtotal, Materials and Supplies			$ 860,000	5.0%
Subtotal, Variable Operating Costs			$13,318,300	78.5%
Subtotal, Fixed and Variable Operating Costs			$16,969,900	100.0%
	30-Year Levelized Costs			
Levelized Fixed Operating Costs			$ 6,886,900	13.4%
Levelized Variable Operating Costs			$25,118,300	49.0%
Levelized Fixed Charges			$19,278,000	37.6%
Levelized Total Annual Operating Cost			$51,283,200	100.0%

size coal. However, this technique is ineffective for removing very fine size pyrite particles that are entrapped in the froth or attached to the coal particles.

Two-stage flotation, as its name implies, incorporates a second flotation stage where fine coal particles are further cleaned. This process, developed by the U.S. Department of Energy and granted a patent in 1974, consists of a first-stage flotation step to remove coarse, free pyrite and other refuse in the tailings. The clean coal from the first stage flotation is then repulped and treated with a depressant, a pyrite collector, and a frother to selectively float the remaining pyrite in a second stage.(19).

Bench-scale and pilot plant experimental work on this process was conducted on two run-of-mine coals: Pittsburgh seam coal from Greene County, Pa. and Lower Freeport seam coal from Cambria County, Pa. The test results are presented in Table 7-15.

TABLE 7-15. TWO-STAGE FLOTATION TEST RESULTS (19)

	Pittsburgh seam, Greene Cty, PA*				L. Freeport seam, Cambria Cty, PA**			
First Stage:	P.S.	T.S.	Ash	Yield	P.S.	T.S.	Ash	Yield
Feed	1.05	1.51	31.6	100.0	2.18	2.58	31.8	100.0
Clean Coal	0.90	1.59	10.1	64.9	0.87	1.40	7.8	62.3
Refuse	1.33	1.36	71.4	35.1	4.36	4.50	71.4	37.7
Second Stage:								
Feed	0.88	1.54	10.4	100.0	0.86	1.40	7.7	100.0
Clean Coal	0.52	1.20	10.1	92.4	0.42	0.97	7.4	90.5
Refuse	5.24	5.68	13.8	7.6	5.07	5.53	10.7	9.5

* 1st stage additive: 0.10 g/kg (0.2 lb/ton) MIBC

2nd stage additive: 0.25 g/kg (0.5 lb/ton) Aero depressant 633 and 0.05 g/kg (0.1 lb/ton) MIBC and 0.35 g/kg (0.7 lb/ton) potassium amyl xanthate.

* 1st stage additive: 0.05 g/kg (0.1 lb/ton) MIBC
0.30 g/kg (0.6 lb/ton) Aero depressant 633, 0.05 g/kg (0.1 lb/ton) MIBC and 0.40 g/kg (0.8 lb/ton) potassium amyl xanthate.

These test results show that 70 percent of the pyrite present in the Pittsburgh seam coal was removed from this process at 60 percent yield. With the Lower Freeport seam coal pyrite removal of 90 percent was achieved at 56 percent yield. Analysis of the results from Table 7-15 also indicate that most of the ash in the feed coal is removed in the first stage, and most of the pyrite removal takes place in the second stage.

Pilot plant tests were also conducted to determine the optimum process operating conditions. It was found that (1) larger amounts of potassium amyl xanthate improved pyrite removal (especially with the Lower Freeport seam coal), (2) shorter retention times in the cells yielded better results, and (3) lengthly conditioning of the feed slurry was unnecessary.

A cost evaluation of the two-stage flotation process was performed as a retrofit to existing coal preparation plants.(20) To incorporate various designs, three coal preparation plant designs with flotation circuits were selected. The cost analysis indicated that the addition of the two-stage flotation to the fine coal cleaning circuit of an existing preparation plant increased the cost of the total plant product by 1.6 to 2.5 percent, or 14¢ to 19¢ per metric ton (13 to 17 cents per ton) of clean coal. If the cost of this addition is added to the fine coal section of the preparation plant, then the increase in the fine coal cleaning cost is between $2.07/Mg ($1.88/ton) and $2.58/Mg ($2.35/ton).

In addition, a hypothetical ultra-fine coal cleaning plant, designed exclusively around flotation, was evaluated. In this process (Figure 7-9) the run-of-mine coal is first crushed in a rotary breaker to 10 cm (4 in.) top size. The crushed coal is then screened at 1.9 cm (0.75 in.). The screen undersize along with oversize material (after it is crushed to 1.9 cm top size) are then wet pulverized in a ball mill to 0.595 mm (28 mesh). The ball mill product is classified by spiral

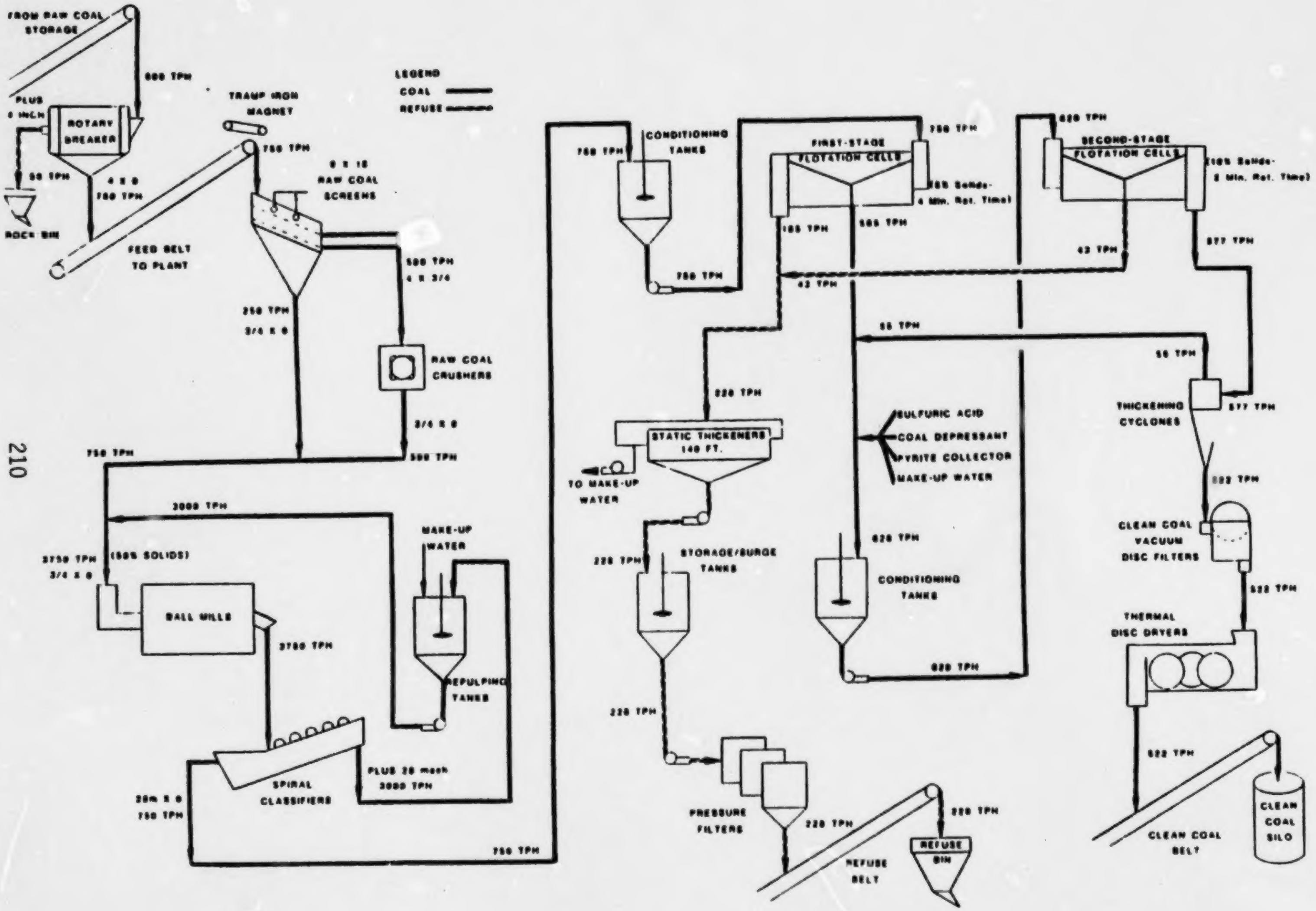
FROM RAW COAL STORAGE
800 TPH
PLUS 6 INCH
ROTARY BREAKER
50 TPH
ROCK BIN
4 X 0
750 TPH
TRAMP IRON MAGNET
FEED BELT TO PLANT
750 TPH
8 X 16
RAW COAL SCREENS
500 TPH
4 X 3/4
250 TPH
3/4 X 0
RAW COAL CRUSHERS
3/4 X 0
500 TPH
750 TPH
LEGEND
COAL
REFUSE
3000 TPH
2750 TPH
3/4 X 0
(50% SOLIDS)
BALL MILLS
3750 TPH
MAKE-UP WATER
REPULPING TANKS
SPIRAL CLASSIFIERS
PLUS 28 mesh
3000 TPH
28m X 0
750 TPH
750 TPH
750 TPH
CONDITIONING TANKS
750 TPH
FIRST-STAGE FLOTATION CELLS
750 TPH
(25% Solids-
4 Min. Ret. Time)
165 TPH
585 TPH
42 TPH
220 TPH
STATIC THICKENERS 140 FT.
TO MAKE-UP WATER
220 TPH
STORAGE/SURGE TANKS
220 TPH
PRESSURE FILTERS
220 TPH
REFUSE BELT
220 TPH
REFUSE BIN
55 TPH
SULFURIC ACID
COAL DEPRESSANT
PYRITE COLLECTOR
MAKE-UP WATER
620 TPH
CONDITIONING TANKS
620 TPH
620 TPH
SECOND-STAGE FLOTATION CELLS
(10% Solids-
2 Min. Ret. Time)
42 TPH
577 TPH
55 TPH
THICKENING CYCLONES
577 TPH
522 TPH
CLEAN COAL VACUUM DISC FILTERS
522 TPH
THERMAL DISC DRYERS
522 TPH
CLEAN COAL BELT
CLEAN COAL SILO

FIGURE 7-9. TWO-STAGE FLOTATION PROCESS

classifiers: The oversize material is recycled to the ball mill. The 0.60 mm x 0 material is conditioned before being introduced into the first-stage flotation cells. The froth material is reconditioned with acid (to adjust the pH), coal depressant and pyrite collector, and then introduced into the second-stage flotation cells. The flotation product is concentrated by thickening cyclones and then dewatered by vacuum disc filters. The dewatered product from the filters is finally dried in thermal disc driers before being sent to clean coal silos. The refuse material from the first- and second-stage flotation cells is concentrated in a static thickener and dewatered by pressure filters.

The cost evaluation of this process was made for a plant handling 681 Mg/h (750 tph) feed coal at 70 percent yield and 93 percent energy recovery, and operating at 40 percent of the time. Based on late 1980 prices, the capital investment was estimated to be $71.1 million, and the cleaning cost was found to be $22.79/Mg ($20.69/ton) of clean coal or $15.85/Mg ($14.39/ton) of raw coal. Summaries of capital and operating-and-maintenance cost estimates are presented in Table 7-16 and 7-17.

TABLE 7-16. CAPITAL COST ESTIMATES FOR TWO-STAGE FLOTATION PROCESS(20)

Raw Coal Storage and Handling	$ 1,215,000
Preparation Plant	34,604,000
Other Facilities and Equipment*	23,402,000
Contingency	11,844,000
TOTAL CAPITAL REQUIREMENT	$71,065,000

* Include dryers, thickeners, conveyors, silos and refuse handling equipment.

OTHER PROMISING PROCESSES

Four recently conceived processes for advanced coal cleaning are being actively developed and could provide breakthrough or significantly influence cleaning in the late 1980's. These processes are discussed below.

TABLE 7-17. OPERATING AND MAINTENANCE COST ESTIMATES FOR THE TWO-STAGE FLOTATION PROCESS(20).

COST CATEGORY	Per Ton Raw Coal	Per Ton Clean Coal
Labor -		
Supervisory (Non-Union)	$ 0.03	$ 0.04
Operating & Maintenance (Union)	0.45	0.65
Overhead -		
Includes Payroll Taxes, Insurance, Welfare Fund, Vacations, Holidays, Group Insurance and Other Fringe Benefits	0.27	0.39
Supplies -		
Operating	1.68	2.41
Maintenance - Repair Parts & Materials Materials Associated with Routine Maintenance	0.80	1.15
Thermal Disc Dryer Fuel -		
Based upon 2,520 gal/hr Fuel Oil Consumption and Cost of Oil @ $1.04/gal	3.49	5.02
Electricity	1.56	2.25
Grinding Media (Ball Mills)	0.25	0.36
Miscellaneous Expenses	0.20	0.29
Operating & Maintenance Cost - Not Including Capital Amortization	$ 8.73	$ 12.56
Capital Amortization - 10 Years - 40% Utilization	5.66	8.13
Total Operating & Maintenance Cost	$ 14.39	$ 20.69
Cost Per Million Btu (12,900 Btu/lb based upon 10-12% Product Moisture)		$ 0.80

Molten Alkali Leaching

The Gravimelt process, being developed by TRW, is based on molten alkali leaching of sulfur from coal. Developmental work on this process started after research efforts on Gravichem processes were discontinued.

In the Gravimelt process, 1.19 mm (14 mesh) topsize coal is first introduced into a molten bath of sodium and potassium hydroxides. The mixture, held at 370°C and atmospheric pressure, is then stirred to enhance contact of coal with the bath material. Coal particles floating to the surface are next skimmed off, filtered, and washed with water to remove salts, and sodium and potassium hydroxides. This washing step proceeds with dilute acid washing to remove any acid-soluble mineral matter.

The bench-scale experimental results indicate sulfur removal of 90 to 95 percent from coal as sulfides. Ash in the product was reduced to approximately 0.4 percent. The energy recovery of the process is estimated to be 90 percent by the process developer. The cleaning costs, excluding the cost of coal, are expected to be $22.0 to 27.5/Mg ($20 to 25/ton).

In October 1983, TRW was awarded a $2.86 million contract by DOE to conduct bench-scale research on the recovery and recycle of the molten alkali. The research effort will also include design, construction and operation of a 9.080 kg (20 lb/h) unit to demonstrate the process operation.

Biological Oxidation

An advanced coal cleaning process, based on biological oxidation, is being developed by the Mining and Mineral Resources Research Institute of the Ohio State University.(19) In this process, coal is crushed and suspended in an air-bubbled liquid medium containing a bacterium. This bacterium, called "Sulfolobus acidocaldarious", possesses an enzyme which catalyzes the oxidation reaction of sulfur into sulfate. The sulfate from this process is carried off as sulfuric acid, and coal is washed with water before utilization.

Tests performed on the Illinois No. 6 coal showed reduction of sulfur from 4.44 percent to 1.97 percent. The process developer estimates that this process can treat coal within three to five days at a cost of $11/Mg ($10.1/ton) (4th quarter 1982 U.S. dollars).

Future plans are underway to test this process on a variety of Ohio coals in a pilot plant that can process from one to five tons of coal per hour.

Supercritical Solvent Extraction -- Southern Illinois University under the direction of Charles B. Muchmore recently received a $200,000 DOE research grant to study the supercritical solvent extraction process. The basis of the process is that ethyl alcohol, above its critical temperature, removes organic and pyritic sulfur from coal. Ethyl alcohol in a gas tube reactor is passed through a coal bed. Ethanol extract is distilled out.

The AFT Beneficiation System -- Advanced Fuels Technology (a subsidiary of Gulf and Western Company) has patented a coal beneficiation process that is similar to froth flotation, but uses different chemicals and a new tank design. The beneficiation process is noteworthy in its ability to remove high percentages of ash-forming mineral matter while achieving high recoveries of clean coal. The process is particularly suited to beneficiate lower rank coal (e.g., subbituminous coals) that normally cannot be cleaned well by froth flotation.(20)

The AFT process uses a unique spraying approach that provides better removal of mineral matter while maintaining high recovery of clean coal. The proprietary chemical reagents that AFT uses are mixed in a dilute coal slurry, as is done with flotation. Reagents chemically bond to the coal, but not the mineral matter. A sphere of influence is created, similar to that created in froth flotation.

The AFT beneficiation process has several distinct advantages over flotation:

- Flocculates are broken up by the shear applied by the spray nozzles. A cleaner coal froth results.
- Forced aeration by spraying, instead of bubble capture, means more of the coal floats and is recovered. Using a forcing method makes the process less sensitive to changes in variables such as water temperature and chemistry, often a problem in flotation.
- The chemical bond attachment of air to coal lasts longer than the adsorption bond formed with flotation reagents, coal removal and dewatering.
- The AFT process can handle particles larger than 28 mesh.

Sample cleaning tests results of the AFT process show 50 percent to 90 percent ash removal at energy recoveries on the order of 85 to 98 percent. Sulfur removal capabilities do not differ from conventional cleaning processes.

SUMMARY AND CONCLUSIONS

In this section five advanced coal cleaning techniques were described in some detail. These techniques include chemical leaching, electrostatic separation, heavy-liquid cleaning, oil agglomeration, and high gradient magnetic separation.

The General Electric Process uses sodium hydroxide to leach sulfur from coal under microwave irradiation. Sulfur removal varying between 70 and 90 percent was achieved from bituminous coals containing 1 to 6 percent sulfur. When compared with the other advanced coal cleaning processes discussed in this section, the G.E. Process is the only process that can remove organic sulfur in addition to pyritic sulfur; however, the process is ineffective in removing ash from coal. The G.E. Process is currently being developed at bench-scale under the sponsorship of the U.S. Department of Energy.

The other four processes described in some detail in this section are the Otisca, AED, High Gradient Magnetic Separation, Oil Agglomeration, and Two-Stage Flotation processes. These processes can remove pyritic sulfur and ash from coal by using different mechanisms. The Otisca process uses an organic liquid for specific gravity separation, the AED process ionizes coal particles and uses electrostatic forces in a dry medium; the HGMS technique relies on the magnetic property differences between the coal and its impurities; and the oil agglomeration and two-stage flotation processes uses the mechanism of surface property differences between coal and pyrite. The amount of sulfur removal by each of these four advanced coal cleaning processes is limited by the pyritic sulfur content of the coal.

These processes have been tested at small scales. As a result, various process configurations have been developed, and cost estimates have been performed for these advanced coal cleaning processes. Some of these processes may look favorable for certain applications. For this reason, direct comparison of these processes for a given application may not be meaningful. For example, the wet HGMS and two-stage flotation processes may be economical in conjunction with coal-water slurry transportation and combustion. The AED process may appear to be favorable if it is applied as a fuel preparation step at the coal-fired power plant site. Similarly, the oil agglomeration process may be coupled with coal-oil slurry transportation before combustion in an oil-fired boiler. Finally, the Otisca process may be used at existing coal preparation plants for fine coal cleaning.

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SECTION 8.0

FUTURE TRENDS IN COAL PREPARATION

DIRECTION OF COAL PREPARATION

At present, only 30 to 40 percent of the nearly 600 million tons of coal consumed annually by electric utilities is cleaned, a drop of 5 to 15 percent in the past ten years. This is partially a result of the fact that raw coal production itself has risen about 35 percent since 1972 while the number of operational cleaning plants has remained level. In the past ten years, utilities have generally turned to high-moisture-level, low sulfur, subbituminous western coals based on the industry philosophy that the cheapest fuel produces the cheapest energy.

Developing circumstances, however, are making coal cleaning more economical. These include: higher coal prices and transportation costs; diminishing coal quality due to less selective mining techniques; reduction of easy-to-mine coal reserves; the need to increase availability and capacity factors at existing boilers; stringent air quality standards; lower costs for improving fuel quality versus investing in extra pollution control equipment; and a projected 20 percent increase of consumption by eastern and midwestern utilities in next ten years.(1,2,3) In addition recent projections show a 4.4 percent growth rate in production of Northern Appalachian coals which benefit from coal cleaning. Midwestern coal, which is most amenable to cleaning, is forecasted to have a production decline until 1990, then grow at an average rate of 3.9 percent a year.(4)

Discussions with coal and utility industry personnel support the relatively optimistic outlook for coal preparation. They believe the increase is likely because:

- high ash contents in ROM coal are pushing utilities toward cleaning to meet boiler specifications;
- current research on the benefits of cleaning is expected to indicate considerable savings to utilities;
- tight markets are forcing coal companies to offer better fuel products to be competitive.

Counter arguments to increased cleaning reflect continuation of current conditions including, increased availability of western coals, stable oil prices, decreased metallurgical coal demand and slow orders for new coal-fired units.

Economic Conditions

Much of the future demand for clean coal can be absorbed by current idle capacity in the preparation industry. Coal consumption in 1982, was projected to be lower than in 1981 reflecting current poor economic conditions. In fact, for the first time in 40 years there was no growth in the generation of electricity.(5) Utilities continued to cancel or defer construction of new coal-fired boilers. For each 1000 MW of new generating capacity that is delayed, about 3 million tons of coal are not produced and cleaned. By late 1982, in most coal producing regions, the only coal that was being sold was contract coal or coal that was drawn off stockpiles at below cost prices. Medium Btu, low sulfur coal (less than 1 percent sulfur content) could not be sold on the spot market, even at $17 per ton.(6) In an effort to boost demand for cleaned coal, two states - Ohio and Kentucky - funded studies in 1982 of advanced coal cleaning processes and of ways to promote the cleaning process.

The bleak economic situation of the coal industry has resulted in labor cutbacks and closings at mines and preparation plants. In addition, the National Coal Association broke off its relationship with Bituminous Coal Research, Inc., and discontinued its internal research group in an effort to reduce cost burdens on its member companies. The utilities are taking advantage of the current situation by breaking contracts for high sulfur coals and writing new contracts on low sulfur coals that are available and relatively inexpensive as compared to higher expected future prices. The general consensus is that the downturn is temporary and an upturn in coal demand will follow any economic recovery.

Coal Company Outlook

To compete in today's coal market, most large coal company's are cleaning high and medium sulfur coals and improving mining techniques. Several industry representatives stated that they are investigating modifications at all their preparations plants in order to offer better products to their customers. Blending the good quality and poorer quality coal at the preparation plant is becoming common practice to produce an average coal blend that meets product specifications. Coal companies expect to prepare all exported steam coal, including western bituminous coals that are shipped to Asian markets, and hope to deliver more clean coal to utilities as the benefits of better quality fuels are understood. One representative noted that after contracts expire for its ROM coal, the coal company usually builds a preparation plant to make the coal more marketable.

Several representatives were quite pessimistic about the future of coal preparation, especially in the established eastern and midwestern coal fields. Factors such as the thinning of mineable seams, the financial instability of many small mining companies, increased environmental costs, and higher bonding requirements do not bode well for the future of many mining companies. The future will be brighter once oil prices put alternative fuels and feedstocks in a competitive position, but that may be 15 to 20 years away.

Barriers to expanded coal cleaning include the need for:(2)

- better quality control in cleaning
- improved techniques for separation of fine pyrite

- data on the benefits accruing to boilers
- better control of leachate from solid wastes
- more information on sulfur removal potential, and
- monetary incentives to use or produce clean coal (i.e., tax considerations).

In addition, uncertainty surrounds current legislation and regulations, such as the acid rain issue, the Clean Air Act, and the effluent guidelines requirements for preparation plants.

The long term outlook for increased coal preparation by the coal companies may be dependent upon the ability to produce a low ash (i.e. less than 3 percent) and low sulfur (i.e. less than 0.5 percent) coal suitable for use with coal-water mixtures in (converted) oil-fired boilers, and synthetic fuel facilities. The problems are that large scale research is needed to produce this type of fuel, the research funds are not currently available, and physical cleaning can not reduce the sulfur to 0.5 percent for most coals. In addition, except for a few individual companies, the coal preparation industry continues to perceive itself in the mineral processing business, using old, established techniques. Research into new cleaning techniques and process controls has been left to universities, research groups, technology firms and the government.

Utility Perception of Coal Cleaning

The traditional attitude among utilities is to view coal cleaning as a technology that adds definable costs and offers hypothetical benefits. Typically utilities have handled coal quality problems by specifying increased design capacity in the boiler; however, that option has become quite expensive. As a result, the utility industry is beginning to show interest in quantifying the cost effectiveness of cleaning. It is generally accepted that coal cleaning provides the maximum benefits to boilers that are burning coal inferior to coal specifications for which the boiler was designed. However, most utilities have no precise data either on the expense incurred from buying cleaned coal or the savings accrued from its use. The information that does exist is highly site specific and generalizations are usually made with caution.(7)

Several major utilities (including TVA and AEP) have already determined that, normally, clean coal is superior to run-of-mine coal. They are typically specifying clean coal for all their boilers burning eastern and midwestern coals. Pennsylvania Electric Co., Columbus and Southern Ohio Electric Co., and TVA have gone the next step and built dedicated coal cleaning plants for specific units to meet air pollution regulations.

Coal washing is also being used as a control technology that permits conversion of oil-fired boilers to coal. For example, at Brayton Point Station (New England Electric System) which recently reconverted from oil back to coal, clean coal from PA, VA, and WV will be burned instead of installing FGD systems. Studies were conducted that showed the plant could operate well within EPA air emission guidelines using clean coal. The decision to use clean coal rather than scrubbers reduced the capital cost of conversion by about half and significantly decreased operating costs.(1)

For utilities interested in building a coal beneficiation plant or producing a washed coal product for testing in their boilers, the Electric Power Research Institute (EPRI) has developed a Coal Cleaning Test Facility (CCTF). The objective is to provide utilities with data to judge the effect of clean coal on existing boilers or on the design of new boilers. EPRI is critically testing the premise that the lowest cost coal produces the lowest cost of electricity. The goal of the EPRI Coal Quality Program is to minimize electricity generation costs for existing and new power plants and to quantify the costs and cost savings associated with improved fuel quality.(8)

Overall, utilities are not against using clean coal, they just do not have sufficient knowledge (nor do the state regulatory agencies) about its advantages to include cleaning benefits in fuel choice decisions. If the tradeoffs of reduced ash and higher energy content protect the customer (i.e., the state regulatory agency perceives clean coal as a least cost option) and meet environmental regulations then the utility industry will have the incentive to use clean coal. An EPRI spokesman has stated that, "Integrated planning and economic studies from coal base to busbar are essential if the coal producer is to adequately cover his capital investment in improving coal quality with a reasonable return." In summary, there is a great need for teamwork between the coal and utility industries, their suppliers and regulatory agencies if electricity is to be produced in the most cost-effective way.(2)

TRENDS IN PLANT DESIGN AND OPERATION

Several industry representatives noted that the relationship between utilities and coal companies has not changed in 20 years. Utilities continue to perceive coal cleaning as a black box that reduces ash components in the coal for an increase in costs. Due to the lack of customer sophistication there has been little incentive for coal companies to improve preparation plant design and operation. Three areas that have seen recent change on research activity are:

- Preparation circuits
- Automatic control
- Productivity improvements

Preparation Circuits--

The current trend in preparation plant circuit design is toward increased use of heavy medium circuits. This trend has resulted from improvements in media recovery and keeping the media clean, and development of new magnetites. The driving force has been the increased cost of coal which has necessitated a reduction in the amount of coal lost to refuse. As discussed in Section 4, heavy medium equipment make sharper cuts than water-only equipment and will normally produce a better quality fuel. Also, heavy medium circuits have greater tolerance for fuel variations and more flexibility than water-only circuits. One exception to this is the Batac jig, which can handle medium size coal, provides sharper separation than Baum jigs, and can change the specific gravity of separation.

Another circuit trend is to provide more intensive fine coal cleaning using froth flotation or similar surface property separation devices. One coal company plans to build fine coal cleaning circuits into all existing plants to improve product quality and to obtain the economic advantage of fine coal recovery.(2) Recovery of fine coals from blackwater ponds is being considered by industry, but current economic conditions have precluded any near term activity in this area.(9) In a related area, United Coal Company is studying direct combustion of fine coal wastes in fluidized bed boilers.

A third trend that is just beginning to gain recognition is the production of several steam coal fuels from one preparation plant. The Homer City Multi-stream Coal Cleaning System (MCCS) is the most noteworthy example, producing a deep cleaned product that is 4 to 5 percent ash and has a potential emission of 580 mg SO_2/J (1.35 lb. $SO_2/10^6$ Btu), and producing a middling coal that compiles with a 1,720 ng SO_2/J (4.0 lb $SO_2/10^6$ Btu) emission limit. The ROM coal would emit about 2,400 mg SO_2/J (5.6 lb $SO_2/10^6$ Btu). The EPA has funded studies to assess the MCCS concept to determine operating characteristics and effectiveness in reducing boiler emissions. The intent of the current program is to perform sufficient equipment and circuit tests to assess the environmental, economic, and operational performance of a MCCS system. United Coal Co. has announced that they are running their preparation plants like refineries, producing several product "grades" and blending to meet market specifications.

Automatic Process Controls--

Another trend in coal preparation is the use of microprocessors for process control. Historically, U.S. coal cleaning plants have relied on manual control. There was no incentive to improve controls in order to increase coal recovery due to low coal prices. However, recent higher prices have coal representatives studying the quality of coal leaving the wash plant from the perspective of process controls and potential washability. Modern preparation plants do have monitored circuits and equipment (using programmable logic computers), but few plants are fully automated from breaker to load-out. One coal company has retrofitted programmable logic computers on a jig plant and has seen increased productivity. The major deficient areas include inexpensive on-line analyzers and flow meters, specific gravity controls and pulp density controls. Work in this area is being pioneered by EPRI at the CCTF, which has a digital computer that activates equipment and monitors operation.

Complete control of the preparation process depends upon development of continuous pyrite and mineral matter monitors. The EPRI Continuous Nuclear Analysis of Coal device (CONAC) provides an elemental analysis of coarse coal (including sulfur) and is being tested at a TVA plant. Another device being tested by EPRI is a continuous in-process sulfur and ash analyzer for coal slurries. EPRI expects a 2 to 5 percent increase in Btu recovery at preparation plants with complete process controls, without loss of fuel quality. Real-time coal analysis can be used at several points in the coal fuel cycle - at the mine, at the power plant receiving station to monitor coal specifications, at the cleaning plant to analyze feed and product coal quality, and at blending facilities to ensure meeting target specifications.(8)

Computer models are being developed as an alternative to real-time monitoring. EPA is currently funding several engineering/modeling studies in support of the MCCS. A computer program has been installed at Homer

City for analysis of test results. Under EPA sponsorship, PENELEC is developing and assessing new engineering models to assist in planning and executing the production of compliance coals with the MCCS. These models will also incorporate MCCS cleaning costs and compare these costs to FGD system costs. EPA is also attempting to define the conditions under which coal cleaning is the best economic alternative for SO_2 control. This task considers boiler capacity, availability and maintenance costs in its evaluation. Raw, middling, and deep cleaned coals, including blending of local and non-local coals, are considered in the study. One utility, TVA is using extensive computer simulation of coal preparation plants to improve washing efficiency. The TVA computer simulation project (co-sponsored by EPA) has three parts; interactive simulation for users with washability and size distribution data to model preparation circuits; batch analysis that provides plant flowstream, material balance, and equipment specifications data for a given flowsheet; and actual plant performance testing for improvement of model algorithms and creation of new programs.(8) TVA (co-sponsored with EPA) has combined capital costs and annual revenue requirements for coal cleaning processes and FGD, and quantified economic benefits of cleaning into one comprehensive computer program for SO_2 control tradeoff studies. Current efforts by EPRI and various utilities (e.g., TVA, Penelec, and Wisconsin Power & Light) to develop both cost and benefits computer programs is another indication that industry is moving in the direction of cleaning plant simulation for improving and optimizing fuel quality.

EQUIPMENT DEVELOPMENT

The research and development area of greatest emphasis in the preparation industry is improvement of washing equipment, particularly fine coal cleaning and dewatering. This is a direct result of the high cost of coal that penalizes coal losses to refuse and the increased fines production from continuous mining equipment. Current fines cleaning relies on flotation processes for which the technology is not well understood. As a result considerable efforts are underway to better define improve and implement flotation. Two related processes, oil agglomeration and Otiska, use organic fluids to separate fines from refuse. The basis for separation is deferential surface properties, similar to flotation principles. These technologies are discussed in greater detail in Section 7.

EPA is sponsoring considerable work in evaluating coal preparation plant equipment, for the MCCS at Homer City, including:

- Flow Measurement -- assesses the most accurate combination of available (slurry) flow measurement equipment and optimize the performance of the selected aggregate system.
- Automatic Slurry Sampling -- evaluates various sampler designs and test sampling equipment for the MCCS system needed to determine the quality and variability of coal characteristics at specified locations in the plant process.,
- Density and Flow Rate Instrument -- evaluates the performance of density and flow rate measurements as a means to control proper separation of pyritic sulfur in the fine coal deep cleaning circuits.
- Equipment Performance Tests -- determines the performance of industrial cleaning equipment and ancillary equipment at the MCCS, quantify their sulfur and ash removal efficiency, and collect data on maintenance, operation, and cost.
- Variability -- assesses the effects of feed coal property variation on equipment, circuit, and plat performance for removing sulfur and ash, and attaining satisfactory yields. Evaluates the effectiveness of selective mining and blending on performance values.

- Clean Fuel -- assesses the effects of deep, cleaned coal (i.e., 2 lb. ash/10^6 Btu) on boiler performance. Evaluates differences in boiler heat rate, operating requirements, and emissions between ROM coal and clean coal.
- Heavy Media Cyclone (HMC) -- determines the characteristics of a HMC on classified fine coal (9 x 100 mesh) at specific gravities near 1.30 (g/ml). Provides fundamental information on operating characteristics, magnetic requirements, and slurry viscosity relative to HMC performance.
- Online Sulfur and Ash Meters -- evaluates prototype on-line sulfur and ash meter developed by PENELEC for its use in characterizing product coal and for improving cleaning plant performance.
- Comminution -- studies the optimum operating conditions of the size reduction equipment for liberating mineral matter while minimizing fines (less than 150 per) production.
- Magnetite Substitution -- uses fly ash with high iron (ferric) oxide content as substitute for magnetite and compare performance of each.

Much of the research and development activities in the 1980's will be associated with the EPRI Coal Cleaning Technology Development Program, including the Coal Cleaning Test Facility. The stated objectives of the program are (1) develop engineering data to improve cleaning plant operation; (2) develop/demonstrate new and improved coal cleaning equipment; and (3) develop/demonstrate low ash coal (less than 0.2 % ash) cleaning processes for production for coal-water slurries.(10) Major equipment demonstration projects planned by EPRI for 1982 and 1983 involve:

- fine coal cleaning by heavy medium cyclones at low (less than 1.35) specific gravities;
- improved prediction models for froth flotation operation;

- enhancement of fine coal dewatering through application of silicon polymers; and
- cleaning of high clay content western coals.

The Department of Energy continues to support work on ultra-fine coal characterization and cleaning techniques and coal washability (i.e., liberation by specific gravity separation of ash and sulfur) determinations for major coal seams. The final coal cleaning technologies studies included specific gravity (both heavy liquid cyclones and dense medium cyclones), magnetic, flotation, and other processes. In FY 83, the DOE evaluated fine coal washability of coals from West Virginia, Southern Appalachia, Alaska, and Western regions. In conjunction with the washability evaluations, DOE is developing pyritic sulfur size distribution curves. For DOE, the Bituminous Coal Research, Inc. continued to identify trace elements in raw coal and their reduction through coal cleaning (See Section 5.2). Another DOE project provides an understanding of the ash chemistry of deep cleaned coals (less than 2 percent ash) to permit prediction of synergistic effects on combustion characteristics upon blending.

DOE has also developed a coal preparation test facility at Ames Laboratory in which DOE can test and evaluate new coal preparation processes equipment, and instrumentation. It is currently being modified to process finer coal under research conditions. Ancillary unit operations currently under investigation by DOE are mechanical dewatering techniques to prepare coal-water mixtures from deep, cleaned, ultra-fine coal slurries, ultra fine coal agglomeration/pelletization, energy-efficient coal crushing concepts, on-line pyrite and ash monitors, and computer-based preparation plant simulator models for improving clean coal quality and yield.

For the majority of coal companies equipment research funding is at a low level or nonexistent. The exception to this is United Coal Company that continues to fund research in development of low ash coals.

Research efforts involve cleaning to 1.3 specific gravity, two-stage froth flotation, and dewatering systems for fine coal.

For the late 1980's most research is expected to center around equipment and circuits that produce very low ash, low sulfur coal to be used in coal-water slurries (CWM) or coal-oil mixtures (COM). The extent and development of these technologies may depend upon the position EPA takes relative to gaseous pollutant emissions from converted boilers. If EPA does not relax sulfur dioxide and nitrogen oxide emission requirements for oil-fired boilers converting to CWM or COM, few conversions will be possible.(11) Boiler controls for SO_2 and NO_x that involve addition of sorbent materials to the fuel cannot be used with oil fired units that have little or no ash handling capabilities. Similarly, existing units have minimal space for retrofitting stack gas cleaning equipment. It is noteworthy that the Canadian federal government recently announced its intention to build a coal-water mixture (called carbogel) pilot plant using a 70:30 mixture of cleaned coal and water based on Swedish technology. If the tests are successful, a 100-Mw power plant will be converted to use the coal-water mixture.

From an environmental controls perspective, most near term research will probably involve attaining zero discharge requirements recently promulgated for new preparation plants and controlling fugitive particulates to meet Preventions of Significant Deterioration regulations, or expected inhalable particulate standards. If the EPA develops radiation standards, some methods will be needed to control radiation from refuse piles, especially if western coals are cleaned.

Research in the 1990's may primarily involve chemical coal cleaning technologies or advanced physical cleaning processes and associated environmental control technologies. Most chemical coal cleaning or advanced cleaning processes are being funded by DOE. These include:

- coal characteristics demineralization, involves laboratory tests of a pyrolysis desulfurization and demineralization technique.

- Microwave Desulfurization (See Section 7.0).
- Fused Salt Process (See Section 7.0).
- Instrumental Characterization of chemically-cleaned coals, that investigates the transformation of ash material in chemically cleaned coals and their removal by acid washing.

DOE is also investigating new ways to sample and identify organic sulfur species in coal to provide a means to evaluate and optimize chemical desulfurization processes.

TVA is currently preparing economic evaluations of an oil agglomeration wet physical coal cleaning process, and high gradient magnetic separation techniques under EPA sponsorship to determine economic feasibility for further development. Selected processes in the developmental stage are discussed in Section 7.0.

On a worldwide basis, the major research thrust concerning coal preparation is the attempt to clean coals that are difficult to wash to meet market specifications. At a recent international coal preparaton conference, a number of papers were presented describing preparation techniques directed at upgrading coals containing high concentrations of ash disseminated throughout the coal matrix.(12) As equipment is developed further, more coals that were not economically cleanable are being washed worldwide. Some countries are trading off plant yield in order to make coals marketable. For example, India is currently designing plants (incorporating froth flotation) at 45 to 50 percent weight yield in an effort to make the coal suitable for coking purposes.(13) Steam coal is not washed in India, although steam coals may have 30 to 40 percent ash. In the area of technology development, countries are funding research in many areas. Examples of such research include assessment of coal reserves and their washability, development of new heavy media fine coal cleaning equipment and slurry flotation circuits for weathered fine coals, use of flotation mechanisms on air pulsated jigs, automation for plant control, research into advanced cleaning techniques (e.g., oil agglomeration and HGMS) , quantification of environmental impacts from coal washing, and use of washer tailings.(13)

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SECTION 9.0

IMPACT OF SO_2 EMISSION REGULATIONS ON COAL UTILIZATION AND COST OF COMPLIANCE FOR A UTILITY SYSTEM

A linear programming (L-P) model was developed to study the effect of SO_2 emission regulations on utility fuel choices. This model (1) determines the optimum energy distribution network for a utility operating various power plants and purchasing fuels from a number of sources, and (2) evaluates the effect of changes in the SO_2 emission regulations on the optimum fuel distribution network and (3) calculates the cost of power generation as SO_2 emissions change.

9.1 DESCRIPTION OF THE SYSTEM MODELED

A utility located in Wisconsin was selected for the L-P model. Factors affecting this selection are as follows. First, the types of coals historically used by power plants of this utility are from different regions in the U.S. They include western, midwestern, and eastern coals. Second, the types of boilers operating in these power plants and their capacities show a great variation. These boilers are of the cyclone and pulverized type with capacities ranging from 60 to over 500 MW. Third, various transportation modes are used from coal sources to these power plants. These transportation modes include unit trains, single cars, barges, and trucks. Fourth, none of these power plants is equipped with an SO_2 control device.

The selected utility for the L-P model operates six power plants denoted as P-1, P-2, P-3, P-4, P-5, and P-6 in this study. Coals received at plants P-1, P-2, and P-3 are crushed to 1.50 inch top size by reversible hammermills to produce a product with a size distribution of 80 to 85 percent passing 1/8 inch. The crushed particles are then combusted in cyclone boilers. Plants P-4, P-5, and P-6 have pulverized coal boilers. At these plants, size reduction for boiler feed preparation is achieved in two stages. In the first stage, the plant feed is reduced to a topsize of 1 to 1.25 inch by ring granulators. The granulator product is then pulverized to 70 percent minus 200 mesh in pulverizers. The flue gases from all six boilers are passed through electrostatic precipitators for particulate removal, and then emitted into the atmosphere.

The L-P boiler model input parameters associated with the six power plants are given in Table 9-1. Another set of model inputs includes ash disposal costs at each power plant. The handling practices for bottom and flyash at these power plants include sluicing to pond, landfilling, and selling. Table 9-2 shows ash disposal practices and the associated disposal costs at each power plant.

Twelve coal sources were considered as potential feed to the six boilers. These sources include coal mines and coal preparation plants located in seven different states from the western, midwestern, and eastern coal regions of the U.S. These states are Wyoming, Montana, Illinois, Indiana, Kentucky, Ohio and West Virginia. Locations of these coal sources are shown in Figure 9-1, and coal properties are presented in Table 9-3. Among these coal sources, the first eight represent four pairs of raw and cleaned coals (e.g., coal S-6 is obtained by cleaning coal S-5). Among the last four coals, S-10 and S-11 are ROM coals, and S-9 and S-12 are cleaned coals; each coal is from a different source.

FOB prices of the cleaned coals for the first four pairs and the last four coals were obtained directly from published coal price data. FOB prices of the first four ROM coals were estimated through cost analyses of coal preparation operations knowing the process flow diagrams and weight recoveries, and cleaned coal prices.

TABLE 9-1. BOILER INPUT PARAMETERS

	PLANT I.D.					
	P-1	P-2	P-3	P-4	P-5	P-6
Boiler Heat Output (10^{12} Btu/yr)	16.96	10.38	4.32	0.33	24.98	20.14
Annual Operating Hours (h/year)	4,365	5,012	2,897	523	4,961	4,961
% Excess Air	12	15	15	10	20	20
Fraction of Feed S Emitted into Boiler O/H	0.92	0.92	0.92	0.95	0.95	0.95
Fraction Particulates Emitted into Boiler O/H	0.20	0.20	0.20	0.80	0.80	0.80
ESP Temperature (°F)	300	450	300	300	725	725
Comminution Equipment Capacity (tons/h)	218	119	85	36	428	359
FD Fan Pressure Drop (in. H_2O)	60	60	49	6	6	6
ID Fan Pressure Drop (in. H_2O)	-	-	11	11	11	11
Primary Air Fan Pressure Drop (in H_2O)	-	-	-	30	30	30

TABLE 9-2. ASH DISPOSAL PRACTICE AND COSTS AT EACH POWER PLANT

Power Plant	Type of Ash	Practice	Unit Disposal Cost* ($/ton)
1	Bottom ash	Sluiced to pond (1/3 mile) and sold	0.00
	Flyash	Sluiced to pond (1/3 mile)	5.25
	Total ash (80% bottom ash + 20% fly ash)		1.05
2	Bottom ash	Sluiced to pond (1/3 mile) and sold	1.25
	Fly ash	Sluiced to pond (1/3 mile)	5.25
	Total ash (80% bottom ash + 20 % fly ash)		2.05
3	Bottom ash	Sluiced to pond (1/3 mile) and sold	-0.75
	Fly ash	Sluiced to pond (1/3 mile) and landfilled	2.75
	Total ash (80% bottom ash + 20% fly ash)		-0.05
4	Bottom ash	Trucked 7 miles and landfilled	1.70
	Fly ash	Trucked 7 miles and landfilled	1.70
	Total ash (20% bottom ash + 80% fly ash)		1.70
5	Bottom ash	Sluiced to pond (1/3 mile)	5.50
	Fly ash	57% sluiced to pond	5.25
		19% stored in silo, and then trucked for landfill	1.50
		24% sold	-2.75
	Total Ash (20% bottom ash + 80% fly ash)		3.20
6	Bottom ash	Sluiced to pond (1/3 mile)	5.50
	Fly ash	40% stored in silo, and then trucked for landfill	1.50
		60% sold	-2.75
	Total Ash (20% bottom ash + 80% fly ash)		0.26

*Minus sign indicates revenue.

TABLE 9-3. SELECTED COAL SOURCES AND COAL PROPERTIES

	S-1	S-2	S-3	S-4	S-5	S-6	S-7	S-8	S-9	S-10	S-11	S-12
Coal Seam	Ill.No.5	Ill.No.5	Ill.No.6	Ill.No.6	Ind.No.3	Ind.No.3	Blend of Lwr.Free. +Pittsburg +Sewickley	Blend of Lwr.Free. +Pittsburg +Sewickley	Lwr.Kitt.	Anderson	Rosebud	KY No.4
County	Foulton	Foulton	Randolph	Randolph	Clay	Clay	Harrison	Harrison	Clay	Campbell	Rosebud	Hopkins
State	IL	IL	IL	IL	IN	IN	OH	OH	WV	WY	Montana	KY
Source Capacity (tons/year)	1.1×10^6	0.53×10^6	1.0×10^6	0.76×10^6	2.0×10^6	1.4×10^6	4.15×10^6	2.9×10^6	0.9×10^6	20×10^6	19.1×10^6	0.72×10^6
FOB PRICE ($/ton)	18.09	32.00	15.82	27.50	11.27	21.00	15.11	25.26	25.00	8.07	12.10	22.50
Carbon*(%)	45.6	60.3	60.3	62.5	51.5	59.3	51.3	69.8	70.3	48.5	37.7	64.7
Hydrogen*(%)	3.2	4.3	4.2	4.3	3.7	4.3	3.5	4.7	4.5	3.7	5.3	4.4
Oxygen*(%)	5.3	6.9	7.8	8.0	6.2	7.1	4.3	5.9	5.5	12.2	21.8	5.5
Nitrogen*(%)	0.7	1.0	1.3	1.3	1.0	1.1	0.9	1.3	1.3	0.6	0.6	1.2
Total Sulfur*(%)	2.55	2.48	4.21	3.14	4.85	3.62	3.00	2.80	0.80	0.30	0.70	3.20
Ash*(%)	32.1	10.5	12.7	9.6	23.6	10.9	30.0	9.6	11.6	4.7	8.5	8.5
Moisture*(%)	10.5	14.5	9.5	11.4	9.1	13.7	7.0	6.0	6.0	30.0	26.0	12.5
Heating Value* (Btu/lb)	8,156	10,500	10,995	11,260	9,700	10,879	9,500	12,500	11,645	8,246	8,701	11,828
SO_2 Emission Parameter**	6.25	4.72	7.66	5.58	10.00	6.65	6.32	4.48	1.37	0.73	1.61	5.41
Ash Fusion Temp(°F)	2,210	2,210	2,250	2,250	2,250	2,250	2,400	2,400	2,800	2,140	2,200	2,250
Mill Correction Factor+	1.07	1.10	1.03	1.08	1.04	1.08	0.89	0.87	0.85	0.93	0.93	1.00

* As received basis.

** SO_2 emission parameter = lb $SO_2/10^6$ Btu heat input to boiler (assuming no sulfur retention in the ash).

+ Mill correction factors were obtained from mill correction curves for product fineness of 70 percent minus 200 mesh.

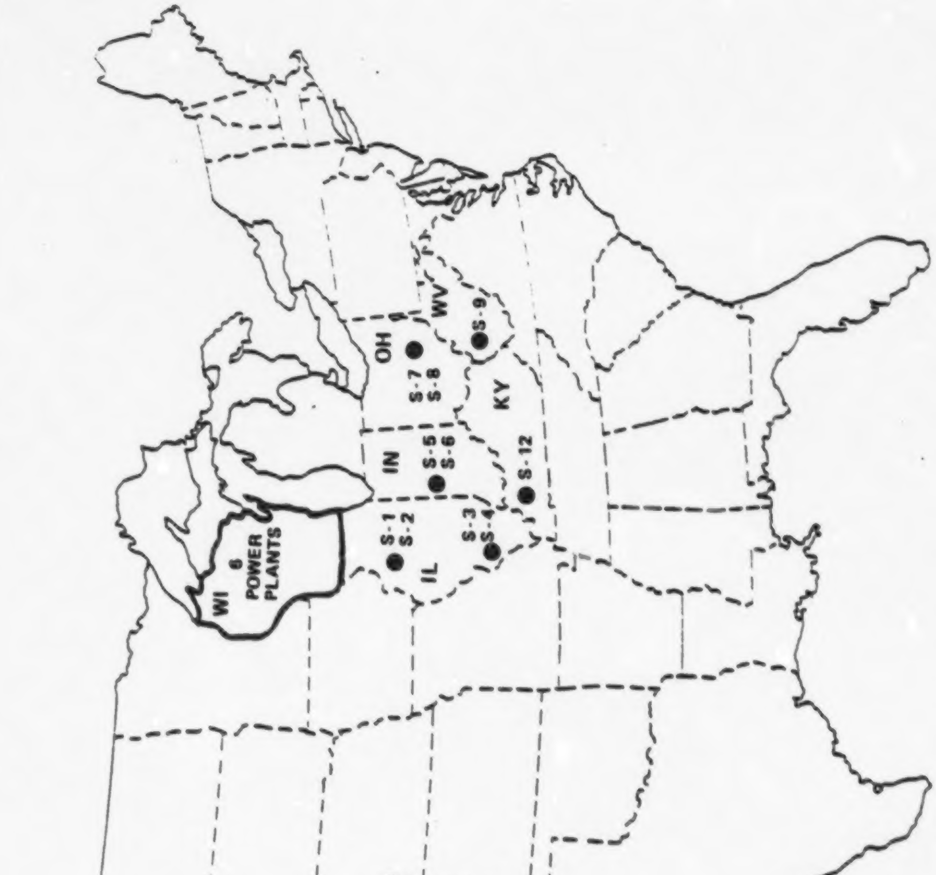

WI
6
POWER
PLANTS
MT
WY
S-11
S-10
IL
S-1
S-2
S-3
S-4
IN
S-5
S-6
OH
S-7
S-8
WV
S-9
KY
S-12

Figure 9-1. Locations of Coal Sources with Respect to the Utility Power Plants

In the first preparation plant, the plant feed (S-1) is crushed to 4 inch topsize, and the crushed coal is introduced into a jig. The cleaned coal from the jig is screened by two-stage screens. The oversize material is crushed, and the intermediate size coal is dried in a centrifuge before being added to the product (S-2). The screen undersize is further cleaned in a hydrocyclone circuit. The middlings from the jig are crushed and then returned to the jig. The refuse from the jig is dewatered before disposal. The coarse refuse is conveyed to the refuse bin, and fine refuse is purified to a waste pond. The weight recovery of coal for this preparation plant is 70 percent. The cost analysis included estimation of capital and annual operating costs, a profit of 20 percent by the plant operator, and the UMW pension trust.

The design of the second preparation plant (cleaning coal S-3) is similar, but simpler than the design of the first plant. It includes a jig circuit, and a hydrocyclone circuit for the fines. The weight recovery of coal from this plant is 65 percent.

The design for the third preparation plant (cleaning coal S-5) was not available, and the capital and operating costs were estimated from known numbers of equipment types and a plant weight recovery of 70 percent. Types of equipment used at this plant include jigs (2), flotation cells (2), washing tables (32), cyclones (16), centrifuges (13), filters (2), crushers (10), screens (16), sieve bends (8), and thermal dryers (2).

The design of the fourth preparation plant (cleaning coal S-7) includes a jig and a fine coal recovery circuit. This plant has a weight recovery of 75 percent.

Transportation of selected coals, either raw or cleaned to the six power plants is achieved by any of the following means, or combinations thereof: unit train, single rail car, barge, and truck. The transportation means and the unit transportation costs from each source to each power plant are given in Table 9-4.

TABLE 9-4. TRANSPORTATION MEANS AND UNIT TRANSPORTATION COSTS ($/TON) FROM COAL SOURCES (S) TO POWER PLANTS (P)

S P	1	2	3	4	5	6
1	6.31 Unit Train	7.90 Truck & Barge	15.17 Single Car	15.17 Single Car	10.55 Unit Train	10.55 Unit Train
2	6.31 Unit Train	7.90 Truck & Barge	15.17 Single Car	15.17 Single Car	10.55 Unit Train	10.55 Unit Train
3	15.00 Unit Train	6.17 Single Car & Barge	15.00 Single Car	15.00 Single Car	12.00 Unit Train	12.00 Unit Train
4	15.00 Unit Train	6.17 Single Car & Barge	15.00 Single Car	15.00 Single Car	12.00 Unit Train	12.00 Unit Train
5	15.00 Unit Train	14.00 Truck & Barge	19.00 Single Car	19.00 Single Car	15.00 Unit Train	15.00 Unit Train
6	15.00 Unit Train	14.00 Truck & Barge	19.00 Single Car	19.00 Single Car	15.00 Unit Train	15.00 Unit Train
7	25.00 Unit Train	12.00 Truck & Barge	30.00 Single Car	30.00 Single Car	25.00 Unit Train	25.00 Unit Train
8	25.00 Unit Train	12.00 Truck & Barge	30.00 Single Car	30.00 Single Car	25.00 Unit Train	25.00 Unit Train
9	25.00 Unit Train	12.00 Truck & Barge	30.00 Single Car	30.00 Single Car	25.00 Unit Train	25.00 Unit Train
10	28.45 Unit Train	28.00 Unit Train & Barge	33.45 Unit Train & Truck	33.45 Unit Train & Truck	23.45 Unit Train	23.45 Unit Train
11	21.00 Unit Train	21.00 Unit Train & Barge	26.54 Unit Train & Truck	26.54 Unit Train & Truck	16.54 Unit Train	16.54 Unit Train
12	13.00 Unit Train	8.50 Truck & Barge	19.00 Single Car	19.00 /Single Car	13.00 Unit Train	13.00 Unit Train

9.2 DEVELOPMENT OF THE MODEL

The utility fuel supply and distribution system described in the previous section was modeled in a linear programming (L-P) framework to determine the optimum energy distribution from coal sources to power plants, and to study the effect of SO_2 emission regulations on the distribution network and on the overall costs to the utility.

A L-P model consists of maximizing or minimizing an objective function subject to a set of linear constraints. This section describes the constraints and the objective function of the L-P model developed for the utility fuel supply and distribution system.

The unknown selected for the L-P model is the amount of heat output from a boiler when coal from source S_i is combusted at power plant P_j. The difference between the boiler heat input and the boiler heat output consists of heat losses to the flue gases, ashes, and other means (radiation, etc.). In this study, only heat losses to the flue gases and ashes were considered since, within a given boiler, they are most affected by coal type.

The L-P model consists of nine sets of constraints and an objective function made up of unit costs from ten cost elements. These constraints and the objective function of the L-P model are discussed below.

CONSTRAINTS

- Coal Supply: These constraints relate coal shipments from each selected source to the capacity of that source. The amount of coal supplied by each coal source to the power plants should not be greater than the capacity of that source (mine or preparation plant). There are twelve constraints, one for each coal source.
- Coal Demand: These constraints relate heat outputs from coals received at each power plant to the heat output of the boiler at that plant. The amount of heat generated at a power plant should not be greater

than the heat provided by the coal (or coal mixture) received by that power plant. There are six constraints, one for each boiler.

- Feed Coal Maximum Ash Content: Coals burned in boilers may be restricted by the capacity of the ash collection and removal equipment. The rate of ash removal not only depends on the ash content of the coal, but also on the feed rate of coal to the boiler. In this model, the maximum ash content in the feed coal was restricted to 18.71 lb/10^6 Btu output for cyclone boilers and 16.25 lb/10^6 Btu heat output for pulverized coal boilers. There are six constraints, one for each boiler.
- Feed Coal Minimum Ash Content: Coals burned in cyclone boilers are limited by a minimum ash content to maintain a slag in the furnace. Formation of slag enhances combustion of coal through improved heat transfer within the furnace, and prevents erosion of the furnace by ash particles. In this model, the minimum ash content in the feed coal was restricted to 5.20 lb/10^6 Btu heat output for cyclone boilers. There are three constraints, one for each cyclone boiler.
- Feed Coal Maximum Moisture Content: Moisture in coal reduces the combustion temperature in the furnace section of cyclone boilers, which in turn has an adverse effect on the slag fluidity. The upper limit for the moisture content of the coals to the cyclone boilers was selected to be 16.63 lb/10^6 Btu output. In addition, coals having moisture contents above this value are not desirable for combustion at Plant P-4. There are four constraints, one for each power plant with cyclone boilers, and the fourth for Plant P-4.
- Sulfur Emission Limits: This set of constraints relates SO_2 emissions from coal combustion to the SO_2 emission regulations. The SO_2 emissions from plants P-5 and P-6 are limited to 1.71 and 1.20 lb SO_2/10^6 Btu boiler heat input, respectively. In this study, the fraction of feed sulfur emitted to the boiler overhead was taken to be

0.92 for cyclone boilers and 0.95 for pulverized coal fired boilers. There are two constraints, one for plant P-5 and the other for Plant P-6.

- Particulate Emission Limits: This set of constraints relates the particulate emissions to the particulate emission regulation for each power plant. The particulate emissions at Plants P-1, P-2, P-3, and P-4 are limited to 0.3 lb/10^6 Btu boiler heat input. For Plants P-5 and P-6 the limitation is 0.10 lb/10^6 Btu boiler heat input. In this study, the fraction of feed ash emitted to the boiler overhead was taken to be 0.20 for cyclone boilers and 0.80 for pulverized coal boilers. The amount of particulates removed by ESPs was determined through an ESP performance model developed by Argonne National Laboratory. There are six constraints, one for each power plant.
- Crusher/Pulverizer Capacity: This set of contraints limits the maximum amount of coal that can be handled at each power plant by the capacities of the comminution equipment. These capacities are given in Table 9-1. There are six constraints, one for each power plant.
- Feed Coal Ash Fusion Temperature: The ash fusion temperature of coals used in cyclone boilers are limited to 2600°F. This constraint ensures the presence of a slag in the cyclone furnace to enhance heat transfer and reduce erosion from ash particles.

THE OBJECTIVE FUNCTION

The objective function of this model minimizes all coal quality-related costs to the utility owner operating six power plants. Because twelve coal sources were considered, 72 unit costs (combination of six power plants and twelve coal sources) were calculated and entered into the objective function. The unit costs were expressed in terms of \$/Btu output (costs are based on 1st quarter 1983 U.S. dollars) from the boiler, and consist of the following ten cost elements (also expressed in terms of \$/Btu output from the boiler):

- Cost of Coal Delivered To a Power Plant. This cost element has two components: (1) cost of coal at the source, and (2) transportation cost of coal from each source to the power plant.

- Power Cost for Comminution Equipment. For power plants equipped with cyclone boilers (P-1, P-2, P-3), the power consumption for the hammermill was assumed to be 1.75 kW/tph for a coal having a mill correction index of 1.00. For power plants equipped with pulverized coal boilers (P-4, P-5, P-6), the power consumption was taken to be 0.44 kW/tph for ring granulators and 6.95 kW/tph for pulverizers operating on coals having a grindability index of 100.

- Power Cost for Primary Air Fan: For power plants equipped with pulverized coal boilers this cost element was calculated from the primary air flow requirement, which in turn is related to the moisture content of the feed coal.

- Power Cost for Forced Draft (FD) Fan: The amount of air compressed by the FD fan is the total combustion air required for the cyclone boilers. For the pulverized coal boilers, it constitutes the balance between the total air and the primary air. The quantity of total air for combustion depends on coal characteristics and the boiler operating parameters.

- Power Cost for Induced Draft (ID) Fan: The amount of flue gases generated from combustion of coal in a boiler depends on coal characteristics for specified boiler operating conditions. These flue gases may be carried through the system by generating enough pressure differential across the primary air fan and/or FD fan operating on boiler inlet air. Alternately, the compression action may be shared by the ID fan operating on flue gases. In this study, each of the boilers at plant P-3, P-4, P-5, and P-6 was assumed to be equipped with an ID fan compressing the flue gases at an inlet temperature of 300°F and a pressure of 1 atm. The power requirement for the ID fan was calculated from the flue gas volumetric rate.

- Bottom and Flyash Disposal Costs: The unit ash (bottom and flyash) disposal cost was determined from the coal ash content and the unit disposal costs. The ash disposal practice and costs are presented in Table 9-2 for each power plant.
- Maintenance Costs: The total maintenance cost of a power plant can be considered to include components that relate to the quantity and properties of the feed coal. In a recent study, total maintenance costs of various power plants were related to coal ash and sulfur flow rates. These relationships include linear as well as logarithmic equations. For the purpose of this study, a linear relationship of the following form was assumed:

$$\text{Total Maintenance Cost} = F + FA\cdot(\text{Ash Flowrate}) + FS\cdot(\text{Sulfur Flowrate})$$

where, F, FA, and FS are constants. In this equation F can be considered to include all coal quality independent cost items for a given power plant. Because the objective function of the L-P model minimizes the overall costs, the constant F in the above equation is dropped. The equation reduces to:

$$\text{Coal Quality Affected Maintenance Cost} = FA\cdot(\text{Ash Flowrate}) + FS\cdot(\text{Sulfur Flowrate})$$

In this study, the following values (in terms of $/ton) were assumed for FA and FS:

for cyclone boilers:	$FA = 4.93$	$FS = 17.88$
for pulverized coal boilers:	$FA = 6.30$	$FS = 24.07$.

These values were derived from regression analyses of the above relationship using data from TVA's Paradise (equipped with cyclone boilers) and Widows Creek (equipped with pulverized coal boilers) plants.

- Power Cost for Other Coal Handling Equipment at Power Plants. Other electricity consuming coal handling equipment considered in this study include feeders, conveyors, and coal crackers. The total power consumption for all these pieces of equipment was assumed to be 0.70 kW/tph of coal handled.
- Power Cost for Flyash Handling System. The power requirement to run the flyash handling system was assumed to be 0.435 kW/tph of flyash. The amount of flyash was calculated from the coal ash content and the particulate emission factor of the boilers.
- Power Cost to Compensate for the ESP Pressure Drop. The power requirement to compensate for the ESP pressure drop was estimated on the assumption that the ESP operates at a 0.5 inch WG pressure drop.

9.3 RESULTS AND DISCUSSION

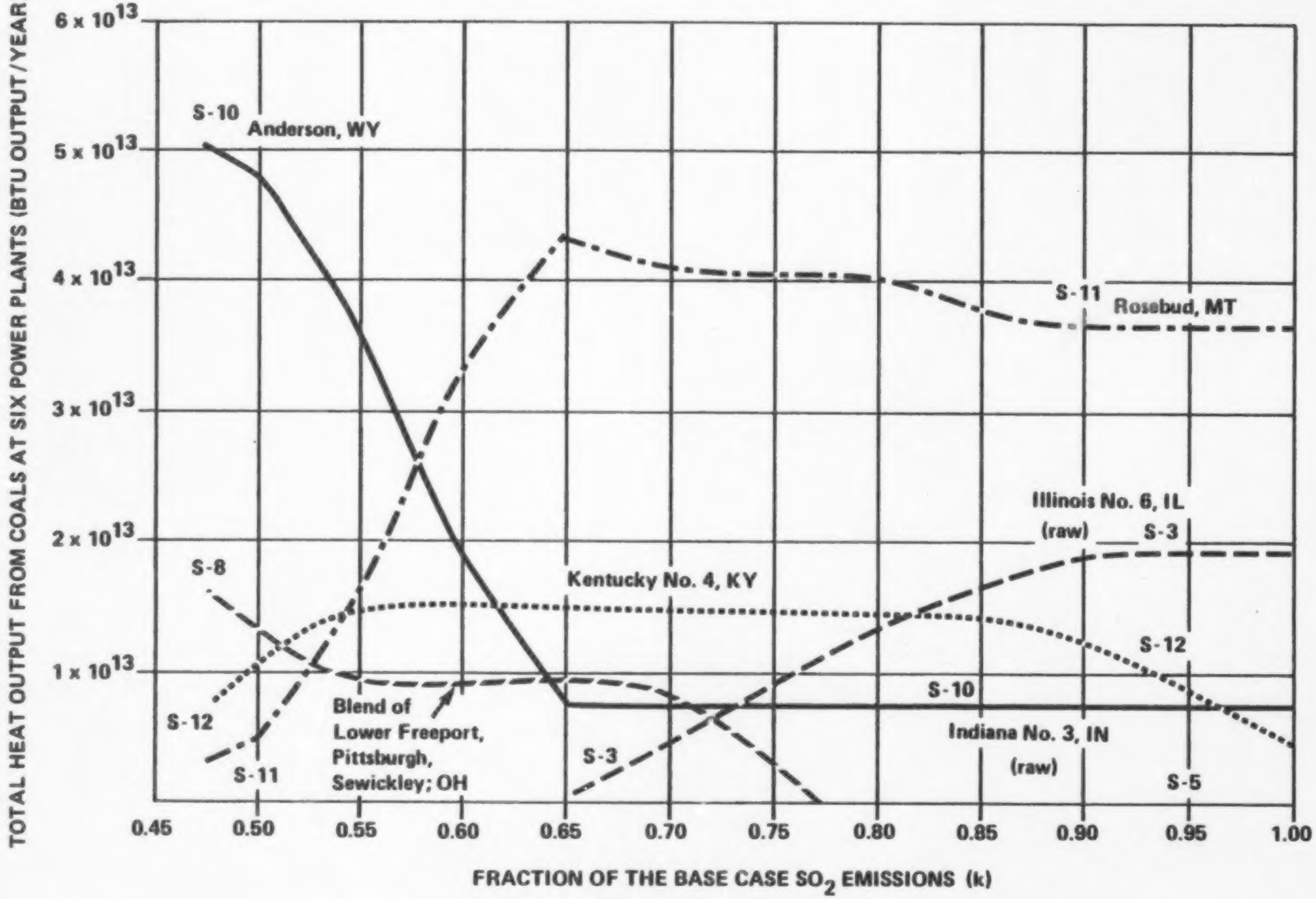
The computer model described in the previous section was run using the Functional Mathematical Programming System on a Univac 1100 computer. The results obtained from these runs are discussed in this section.

The first run included minimization of the objective function subject to the nine sets of constraints. The results of this run are presented in Table F-1 of Appendix F. These results show extensive use of raw coals from sources S-3 and S-5 from Illinois and Indiana when there is no SO_2 emission constraint on the first four boilers. For power plants P-5 and P-6, where the SO_2 emissions are limited to 1.71 and 1.20 lb $SO_2/10^6$ Btu input respectively, low sulfur western coals are used. The total SO_2 emission from combustion of these coals at the six power plants was calculated to be

339×10^6 lb/year (169,300 tons/year), and the total coal related cost to the utility (i.e., value of the objective function) was found to be 148.7 million dollars.

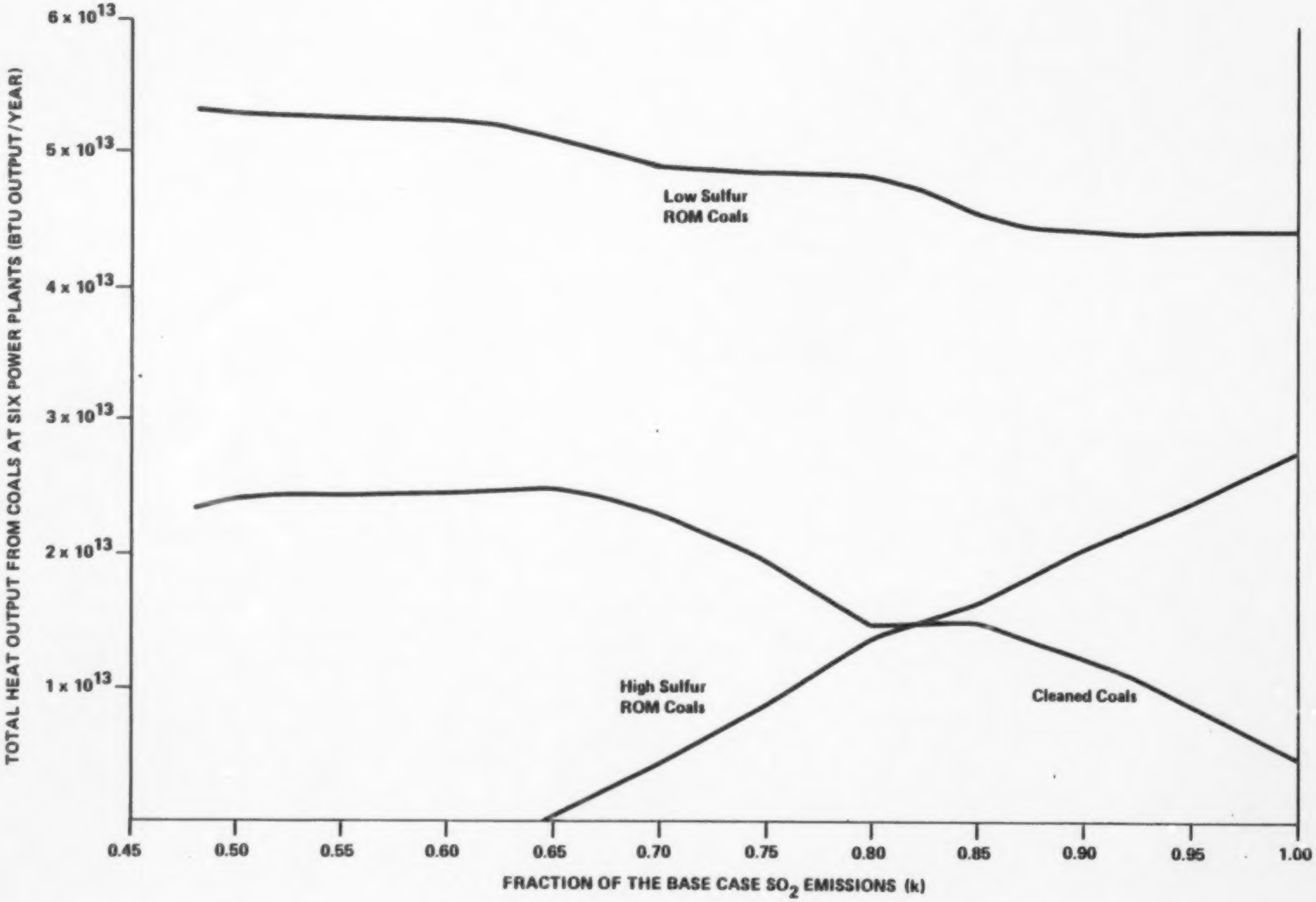
To study the effect of SO_2 emission regulations on utility fuel choices, computer runs were made with an additional SO_2 emission constraint included in the model. This constraint limits the total SO_2 emission from the six power plants to a maximum value set as a fraction k of the total SO_2 emission computed from the first run (i.e., 339×10^6 lb/year). The results of computer runs for various values of the total allowable SO_2 emission (or various values of k) are presented in Tables F-2 through F-12 of Appendix F. These tables show the coal distribution network from coal sources to power plants as well as the amount of heat output from combustion of various coals at each power plant. The total heat output from each coal source for various values of k is shown in Figure 9-2. With lower values of k, cleaned coals from Kentucky (S-12) and Ohio (S-8), and low sulfur ROM coals from Wyoming and Montana are used more extensively. It is interesting to note that cleaned coals from Illinois and Indiana did not appear in any of the optimum solutions mainly because of their higher delivered costs to the utility (in terms of $\$/10^6$ Btu output) than the selected cleaned coals from Kentucky and Ohio. The effect of total allowable SO_2 emissions on the selection of SO_2 control strategies is shown in Figure 9-3.

Coal cleaning appears to be a more attractive SO_2 control strategy than utilization of low sulfur raw coal if the required reduction in the SO_2 emissions is less than 35 percent ($k = 0.65$). At this reduction level, approximately 87 percent of the energy initially provided by high sulfur raw coals (S-3 and S-5) is supplied by clean coals from S-8, S-9, and S-12. When the required reductions in the SO_2 emissions are between 35 and 52 percent, cleaned coal utilization decreases slightly with more extensive use of low sulfur raw coals from western states (S-10 and S-11). Total SO_2 emission reductions above 52 percent require the use of flue gas desulfurization (FGD) technology.



$$k = \frac{\text{TOTAL SO}_2\text{ EMISSIONS FROM 6 POWER PLANTS (LB/YEAR)}}{339 \times 10^6}$$

FIGURE 9-2. COAL UTILIZATION AS A FUNCTION OF ALLOWABLE TOTAL SO_2 EMISSIONS



$$k = \frac{\text{TOTAL SO}_2\text{ EMISSIONS FROM 6 POWER PLANTS (LB/YEAR)}}{339 \times 10^6}$$

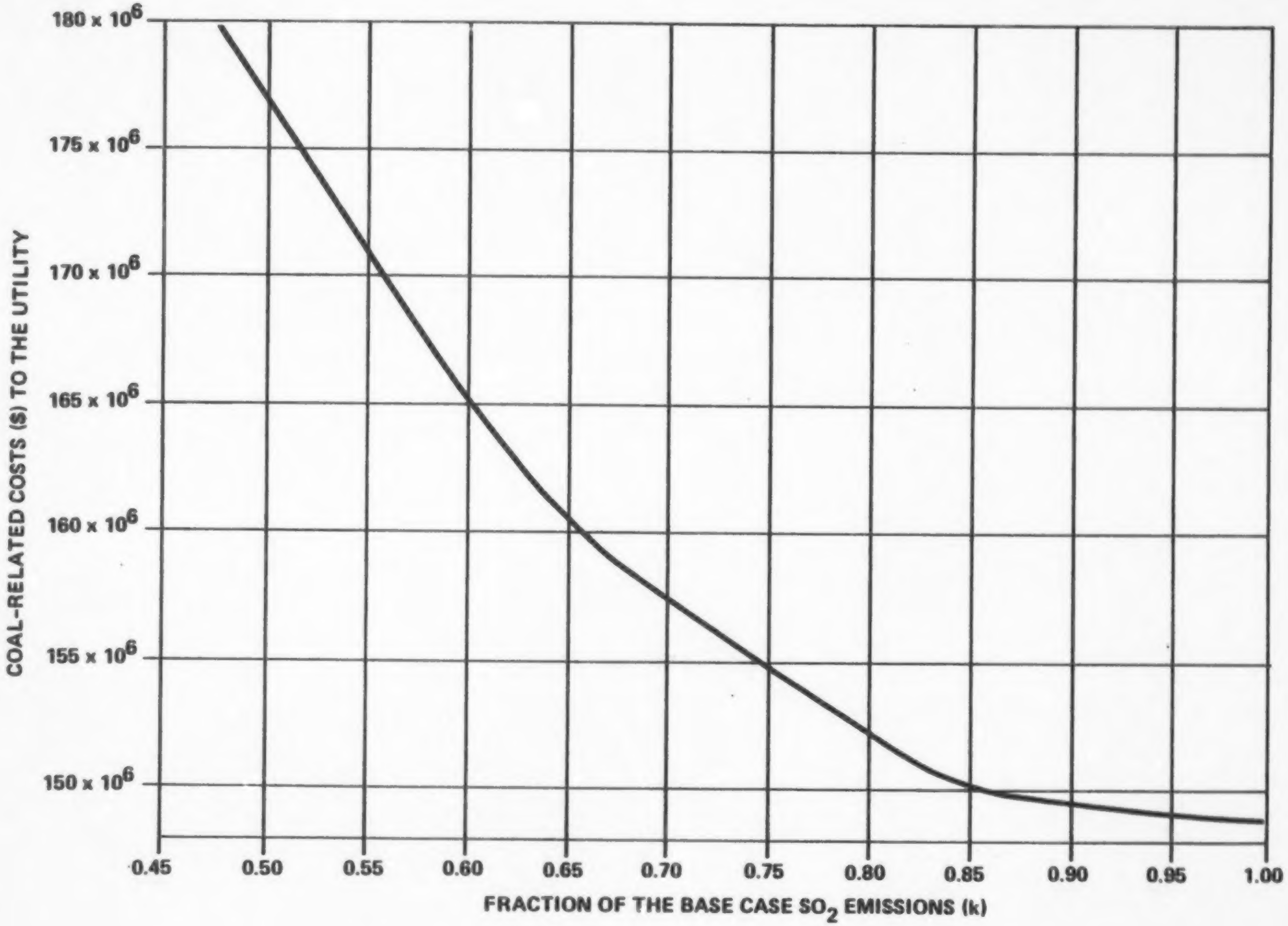
FIGURE 9-3. SO_2 CONTROL STRATEGY

The results also provide data on the relationship between the total maximum allowable SO_2 emissions from the six power plants and the total coal-related costs to the utility. The results shown in Figure 9-4 indicate higher coal-related costs for lower SO_2 emissions (i.e., smaller values of k). For example, the reduction of total SO_2 emission from 339 x 10^6 lb/year to 170 x 10^6 lb/year (i.e., from k = 1.00 to k = 0.50) costs the utility approximately $29 million per year or 17¢ per lb SO_2 removed.

The incremental cost of SO_2 emission compliance for increasing emission reduction from the initial emission level is shown in Figure 9-5. As can be seen from this figure, the cost of SO_2 emission compliance increases exponentially with the reduction from the initial emission level (i.e., k = 1 line). For example, for k=1, the cost of 20 percent SO_2 emission reduction to the utility is $3,400,000, whereas the cost of 40 percent reduction is $16,800,000.

Figure 9-5 also relates the incremental cost of additional SO_2 compliance once some reduction from the current level of SO_2 emissions is achieved. For example, a 10 percent reduction in the total SO_2 emission from the initial level would cost the utility approximately $600,000. However, if the utility has already reduced emissions by 15 percent (i.e., k = 0.85), then the cost of 10 percent additional SO_2 emission reduction becomes $3,600,000.

The model developed in this study can be adapted to simulate flue gas desulfurization technology (with full and partial scrubbing) as a sulfur control option in addition to coal cleaning and use of low sulfur coal. Also, if blending facilities are not available at each power plant then this lack of capability must be incorporated into the model. However, the solutions to both these problems must be obtained by using a mixed-integer program rather than the L-P program computer package used in this study.



$$k = \frac{\text{TOTAL } SO_2 \text{ EMISSIONS FROM 6 POWER PLANTS (LB/YEAR)}}{339 \times 10^6}$$

FIGURE 9-4. COST OF SO_2 EMISSION COMPLIANCE

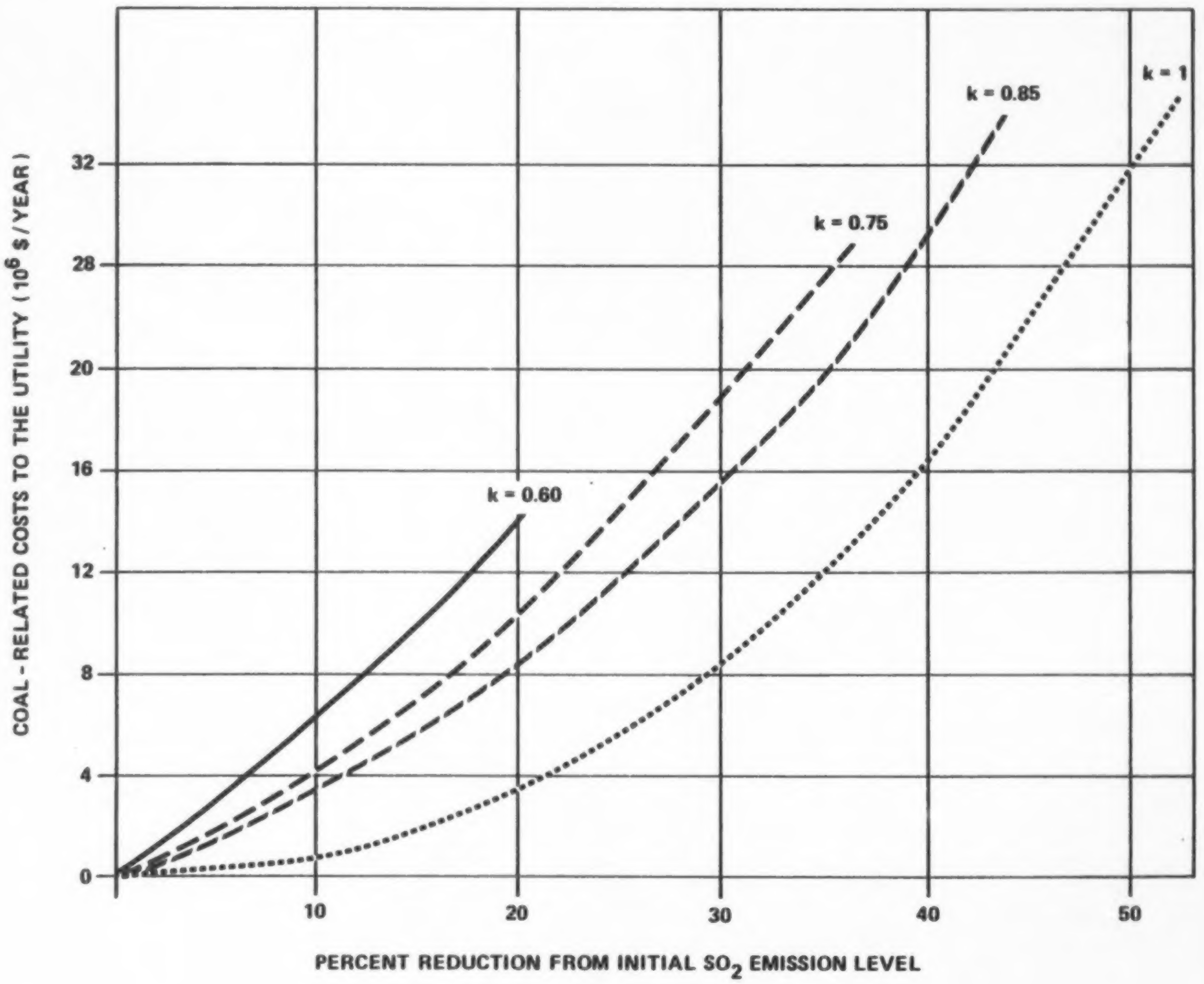


FIGURE 9-5. COST OF ADDITIONAL SO_2 COMPLIANCE

APPENDIX A

REGIONAL AND STATE ANALYSIS OF SO_2 EMISSION REDUCTIONS BY WASHING

A-A

Exhibit A-1. SUMMARY OF WASHABILITY EFFECTS BY STATE

State	Number of Samples	Raw Coal Characteristics Heating Value (Btu/lb)	Raw Coal Characteristics Sulfur (%)	Raw Coal Characteristics Ash (%)	Washed Coal Characteristics* Heating Value (Btu/lb)	Washed Coal Characteristics* Sulfur (%)	Washed Coal Characteristics* Ash (%)	Percent Reduction (lbs $SO_2/10^6$ Btu)
Alabama	10	13,696	1.33	9.50	14,213	1.21	6.09	13
S. West Virginia	16	13,064	0.90	12.73	13,976	0.83	6.69	16
Virginia	8	13,715	0.77	10.04	14,486	0.74	5.03	9
E. Kentucky	7	12,986	1.44	11.48	13,862	1.20	5.53	17
Tennessee	8	13,670	1.18	7.91	14,073	1.02	5.20	16
Pennsylvania	134	12,982	2.56	14.41	13,930	1.67	8.15	40
Ohio	108	12,386	3.87	14.0	13,179	3.00	8.50	28
N. West Virginia	30	12,981	3.36	13.1	13,769	2.61	7.90	27
Maryland	34	12,613	2.40	16.66	13,420	1.75	11.31	32
W. Kentucky	37	12,339	4.05	13.81	13,242	2.96	7.49	35
Indiana	21	13,452	7.17	19.57	13,598	4.33	13.70	28
Illinois	40	13,294	7.82	25.03	13,544	4.56	11.40	41
Iowa	17	11,592	6.74	16.20	12,394	4.59	10.47	38
Missouri	18	11,912	5.52	18.61	13,068	4.11	11.21	33
Oklahoma	14	13,669	2.56	8.95	14,196	2.39	8.37	16
Texas	6	11,018	2.25	19.51	11,903	1.68	14.61	31
Arkansas	7	14,128	3.42	8.23	14,483	2.56	5.93	25
Kansas	10	11,777	4.99	20.30	13,118	3.85	11.30	31
Arizona	6	12,394	0.49	8.05	12,613	0.48	6.48	5
Wyoming	45	12,153	0.84	8.07	12,479	0.76	5.98	11
Montana	23	11,852	0.79	8.33	12,062	0.57	6.92	29
New Mexico	18	11,824	0.64	14.69	12,545	0.60	9.82	14
Utah	21	12,819	0.61	9.88	13,471	0.58	6.19	10
Colorado	34	12,836	0.50	7.66	13,102	0.48	5.95	5
N. Dakota	21	10,700	1.38	11.40	10,951	1.04	9.55	27

*1 1/2 x 100M, 1.6 sp. grav. float.

Exhibit A-2. Distribution of sulfur dioxide emissions parameters for raw coal samples from Northern Appalachian Region.

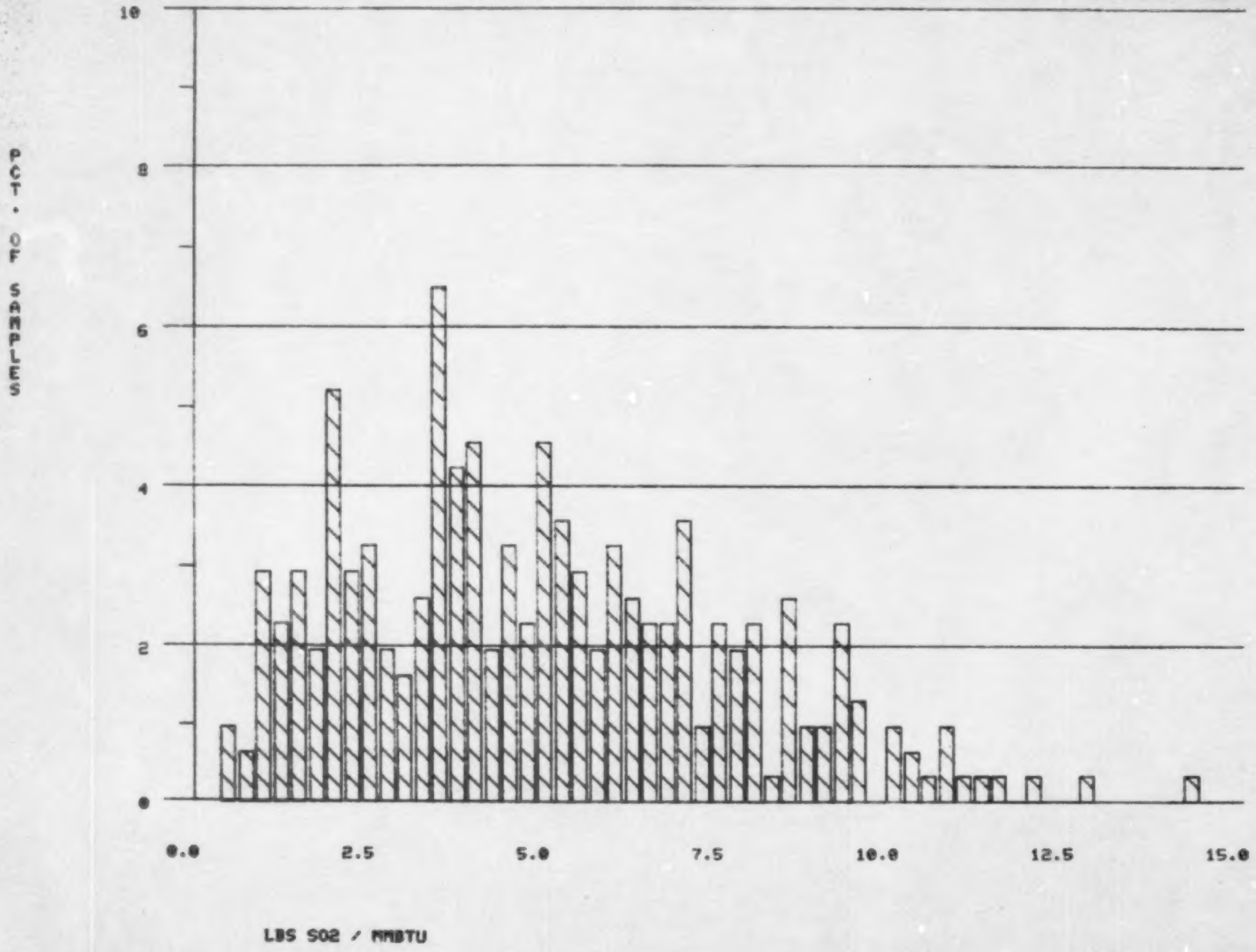


Exhibit A-3. Distribution of sulfur dioxide emissions parameter for washed coal samples from Northern Appalachian Region.

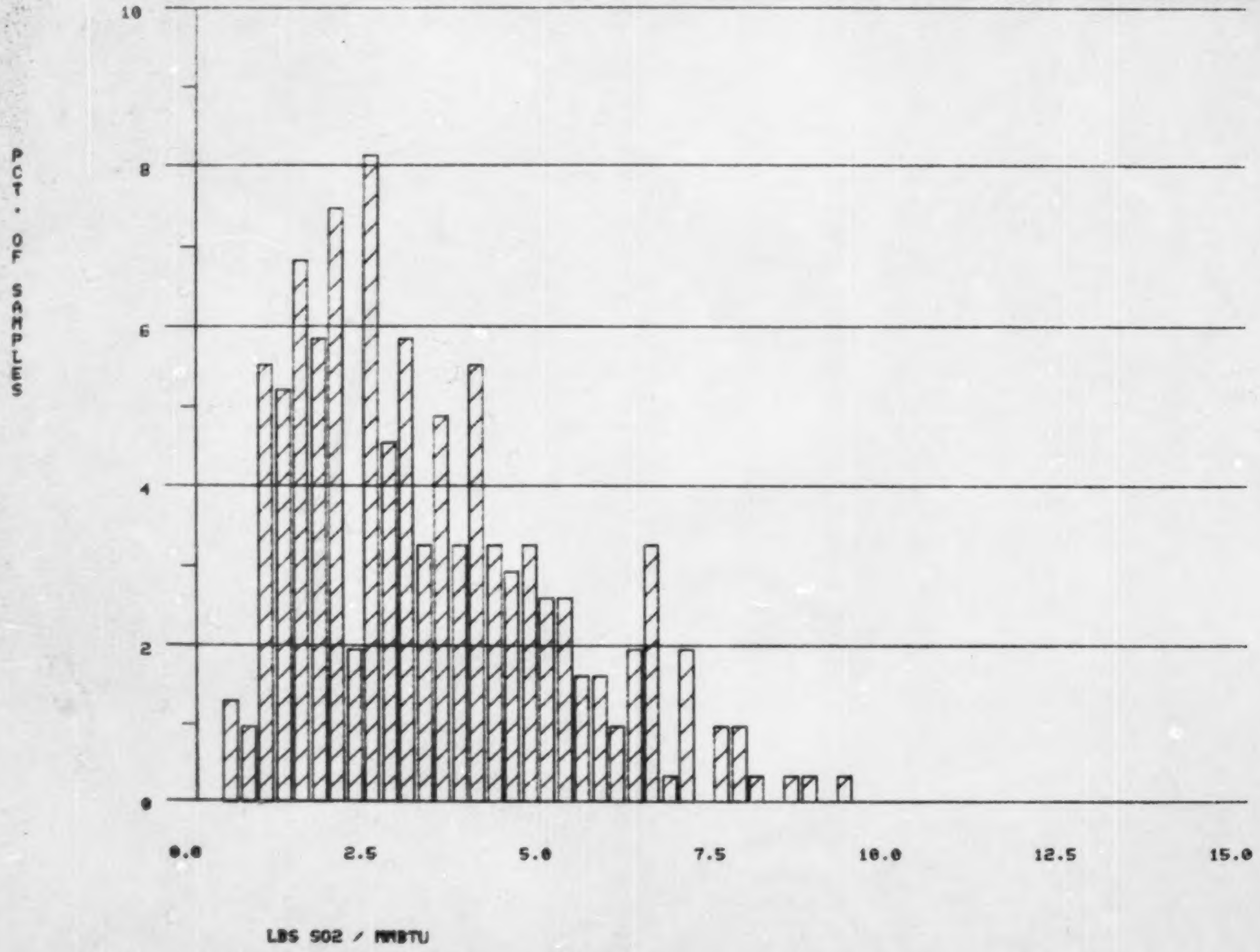


Exhibit A-4. Distribution of sulfur dioxide emissions parameter for raw and washed coal samples from Northern Appalachian Region.

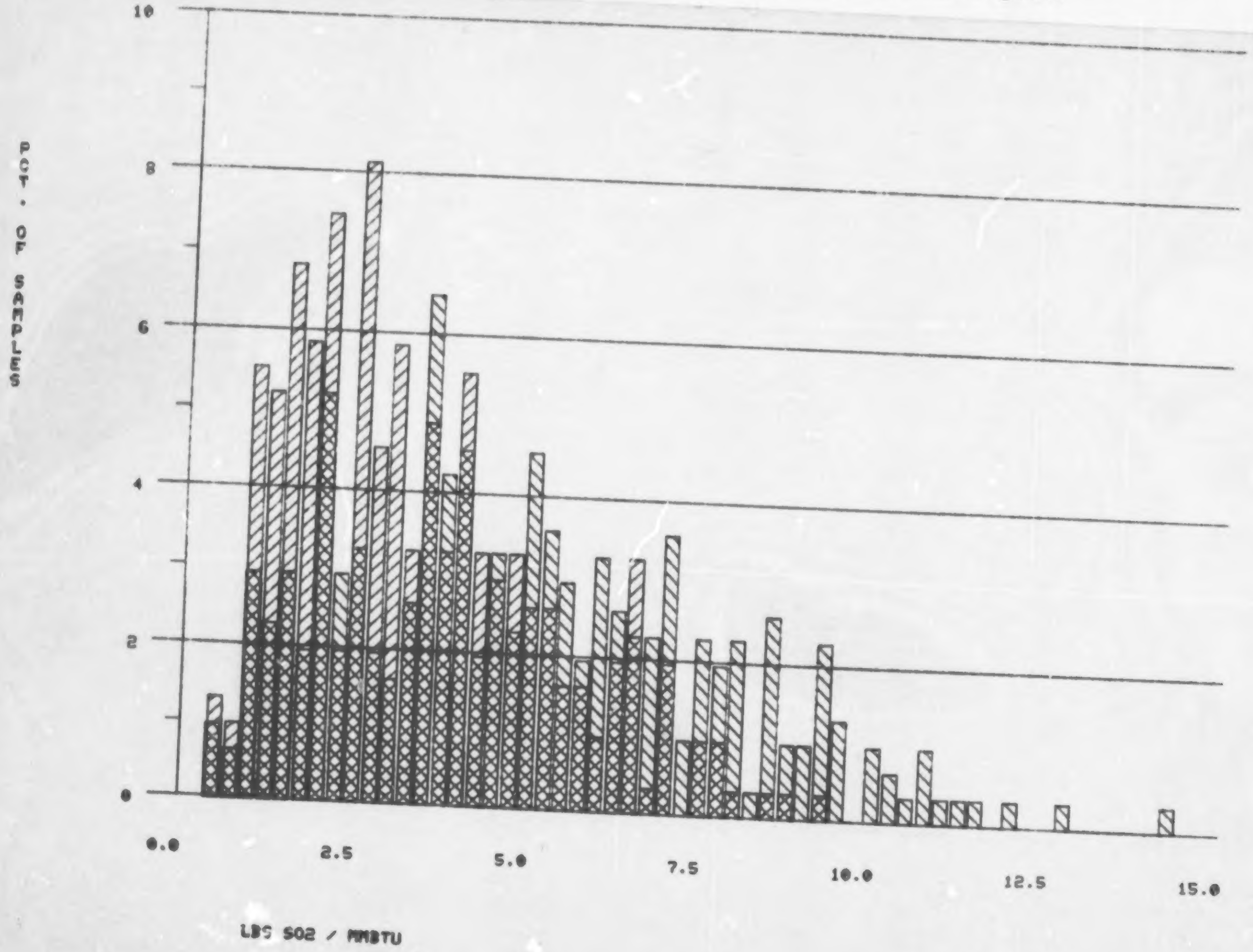


Exhibit A-5. Distribution of sulfur dioxide emissions parameters for raw coal samples from Southern Appalachian Region.

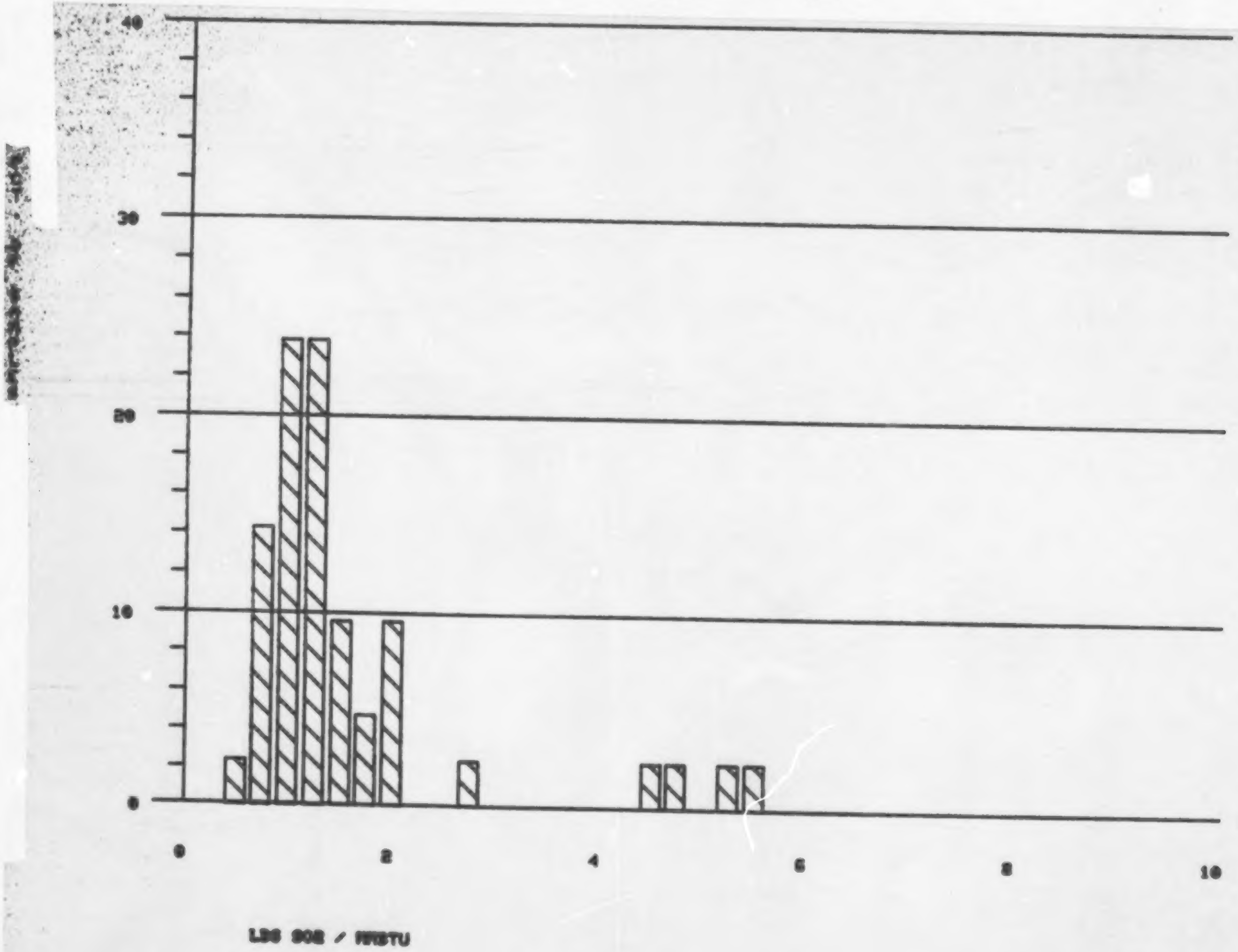


Exhibit A-6. Distribution of sulfur dioxide emissions parameter for washed coal samples from Southern Appalachian Region.

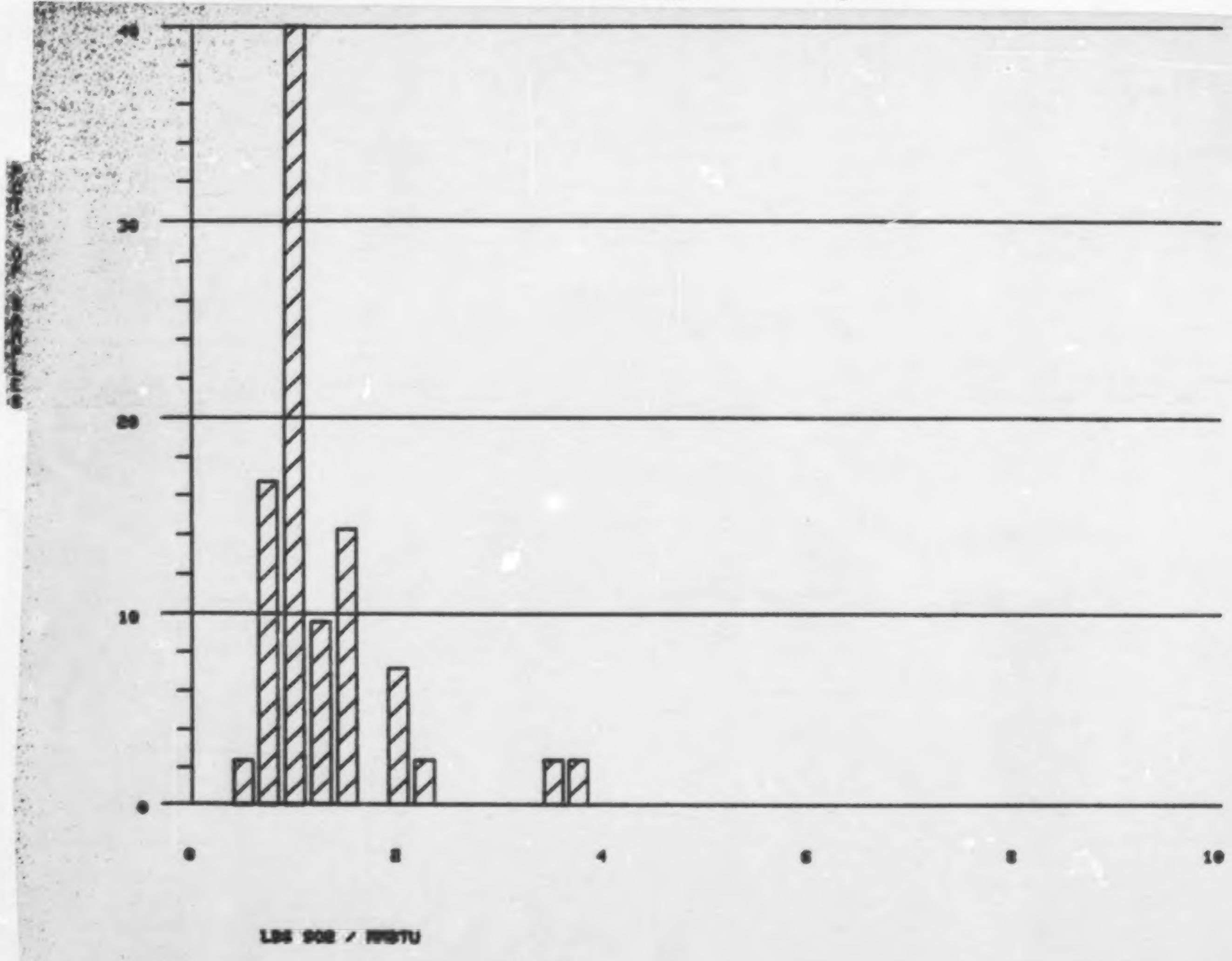


Exhibit A-7. Distribution of sulfur dioxide emissions parameter for raw and washed coal samples from Southern Appalachian Region.

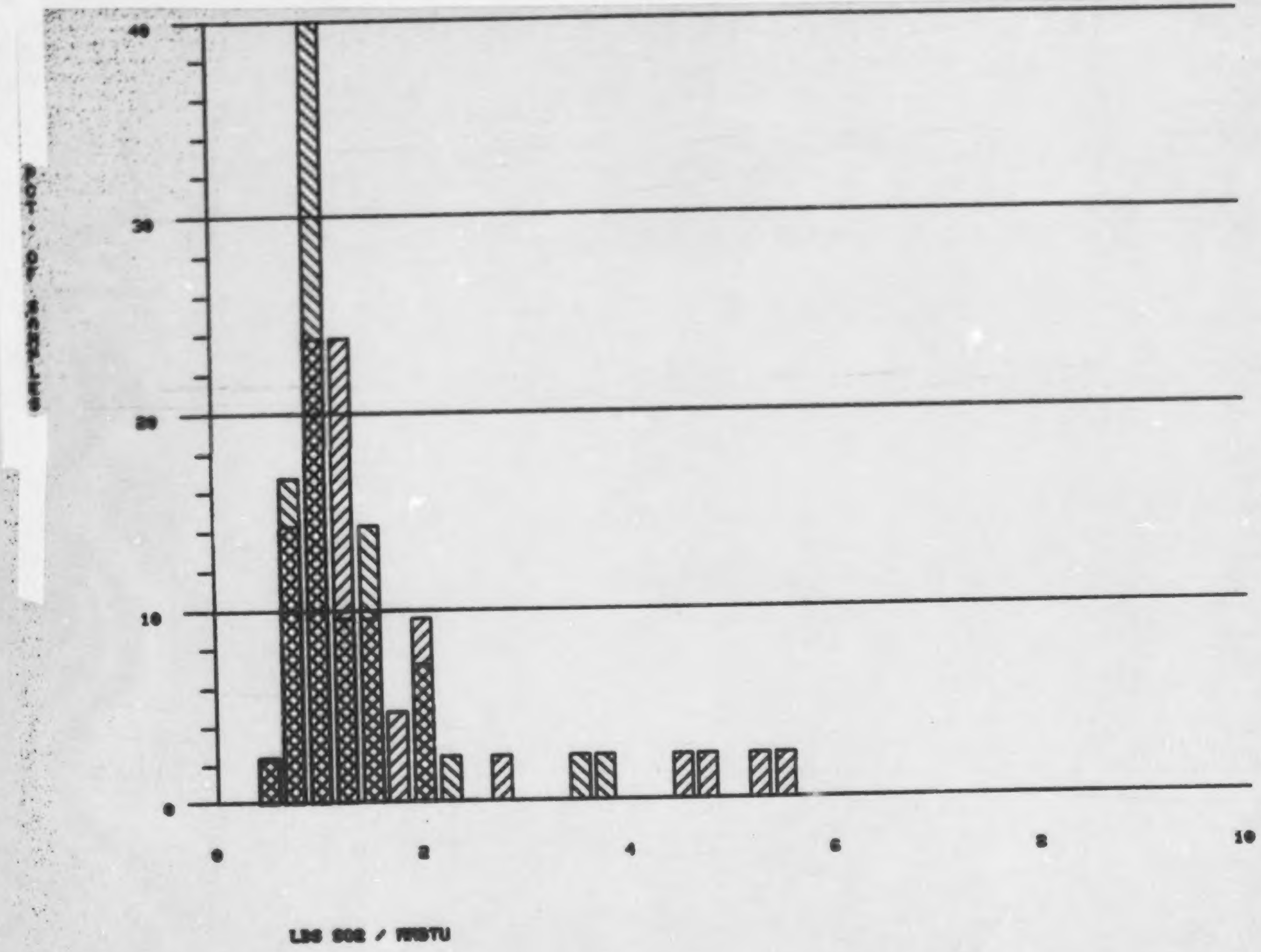


Exhibit A-8. Distribution of sulfur dioxide emissions parameters for raw coal samples from Alabama.

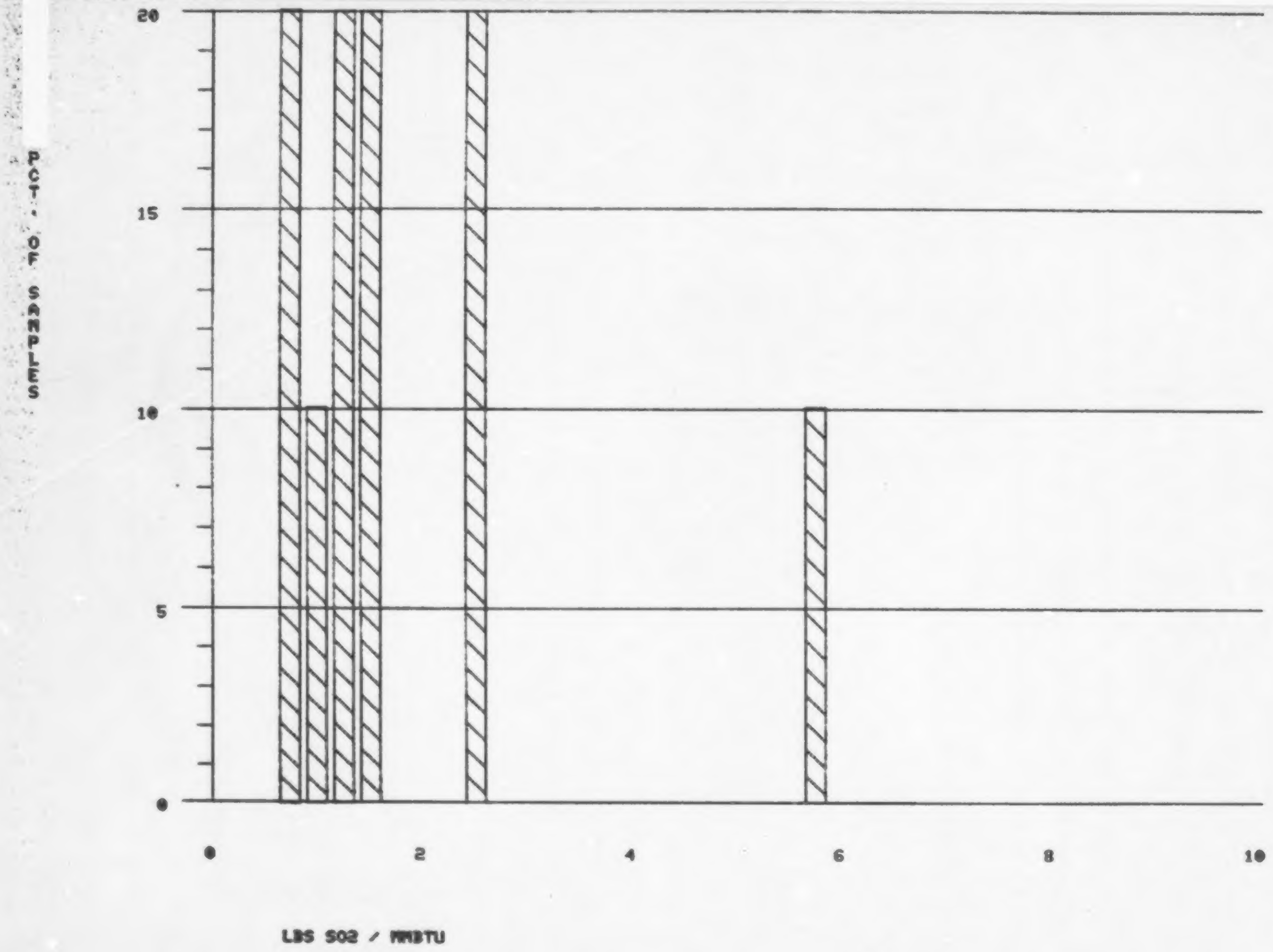


Exhibit A-9. Distribution of sulfur dioxide emissions parameter for washed coal samples from Alabama.

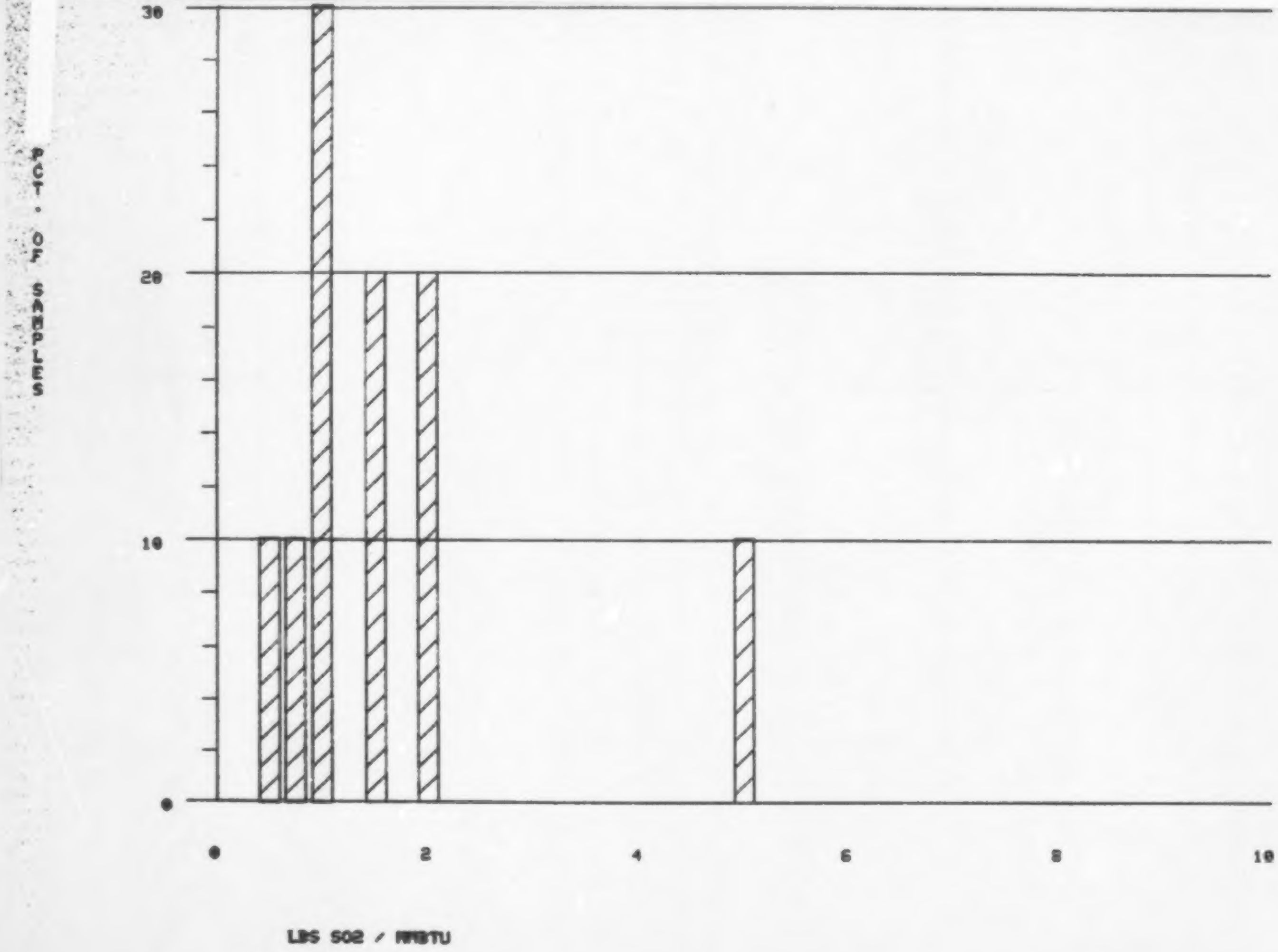


Exhibit A-10. Distribution of sulfur dioxide emissions parameter for raw and washed coal samples from Alabama.

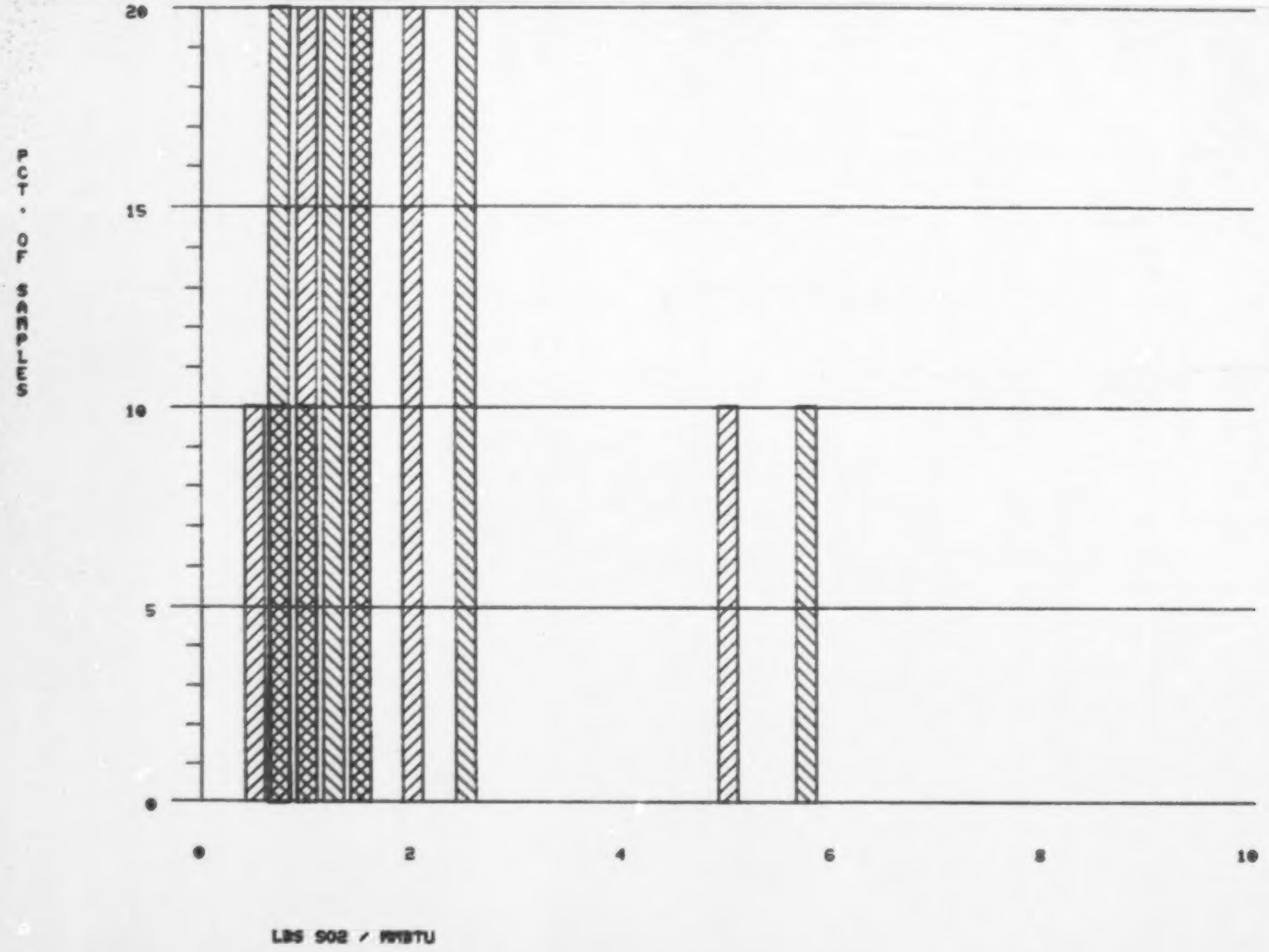


Exhibit A-11. Distribution of sulfur dioxide emissions parameters for raw coal samples from Eastern Midwest Region.

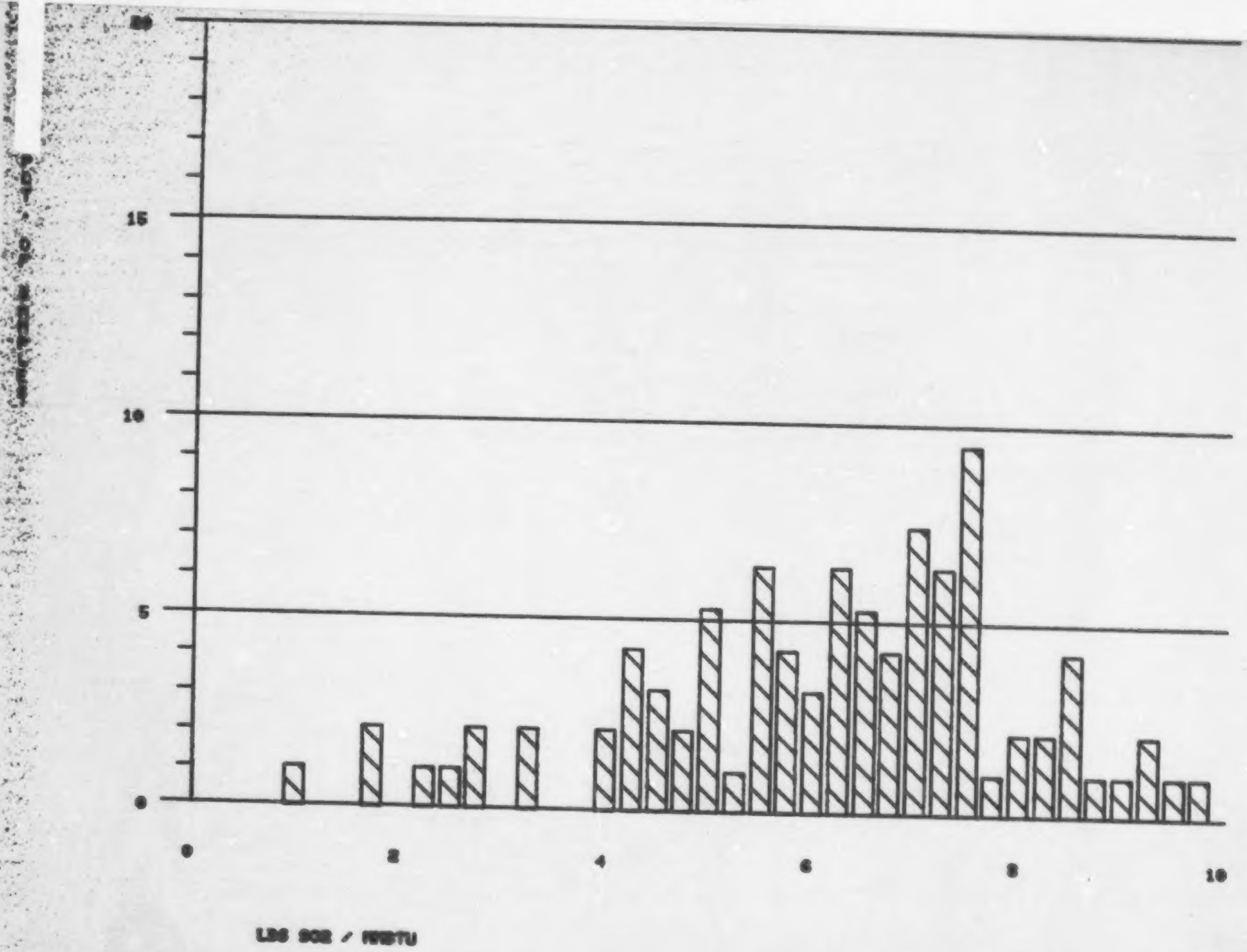


Exhibit A-12. Distribution of sulfur dioxide emissions parameter for washed coal samples from Eastern Midwest Region.

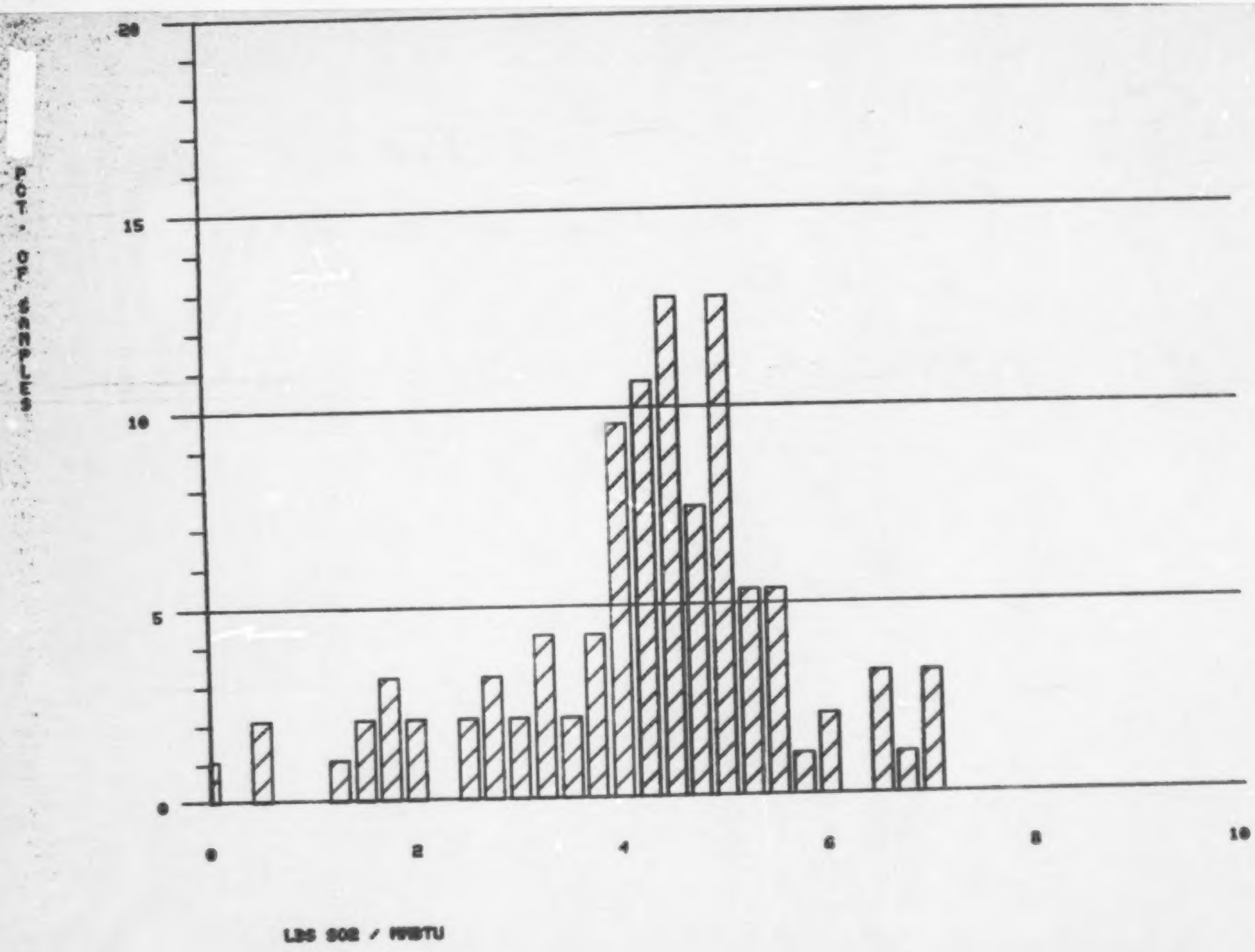


Exhibit A-13. Distribution of sulfur dioxide emissions parameter for raw and washed coal samples from Eastern Midwest Region.

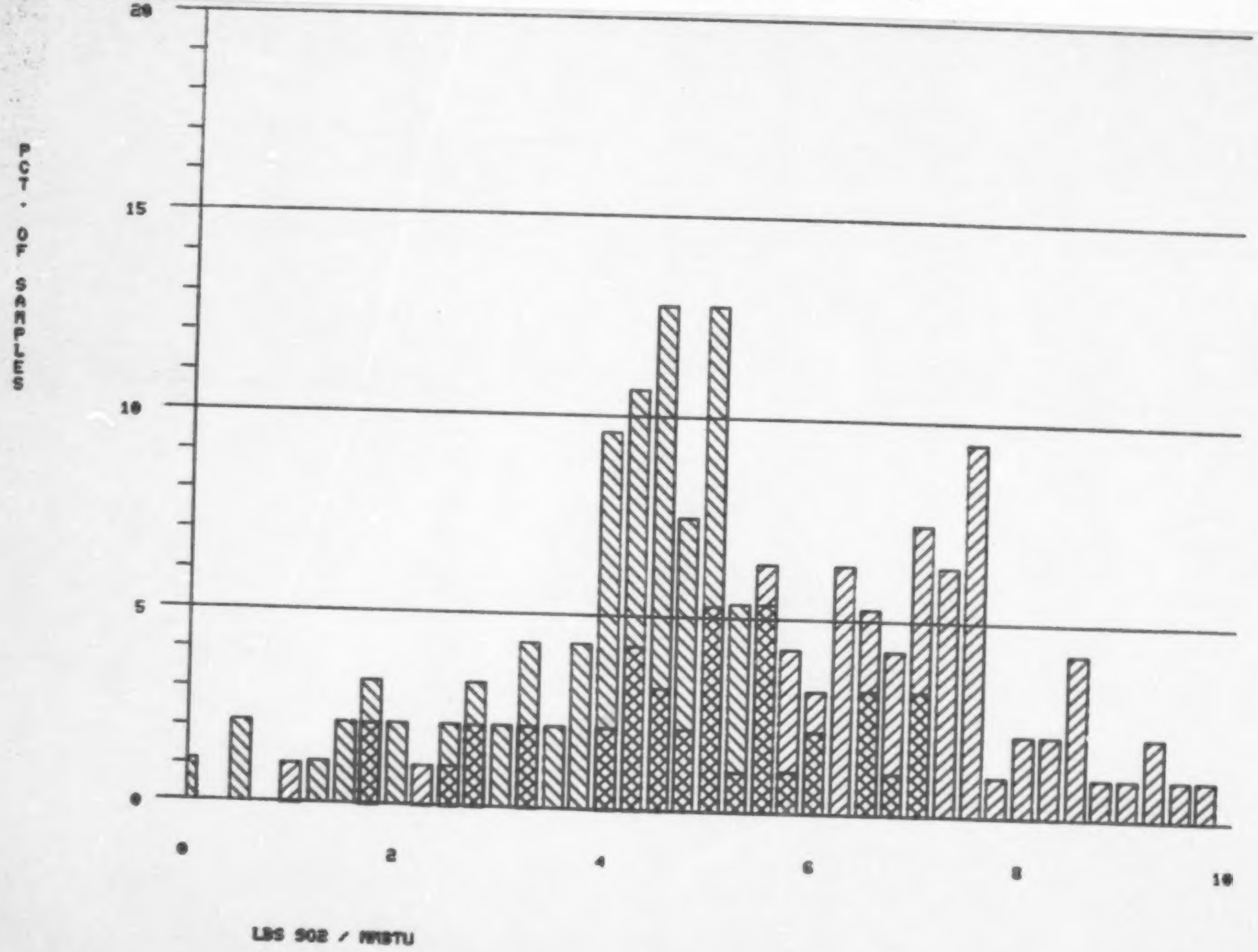


Exhibit A-14. Distribution of sulfur dioxide emissions parameters for raw coal samples from Western Midwest Region.

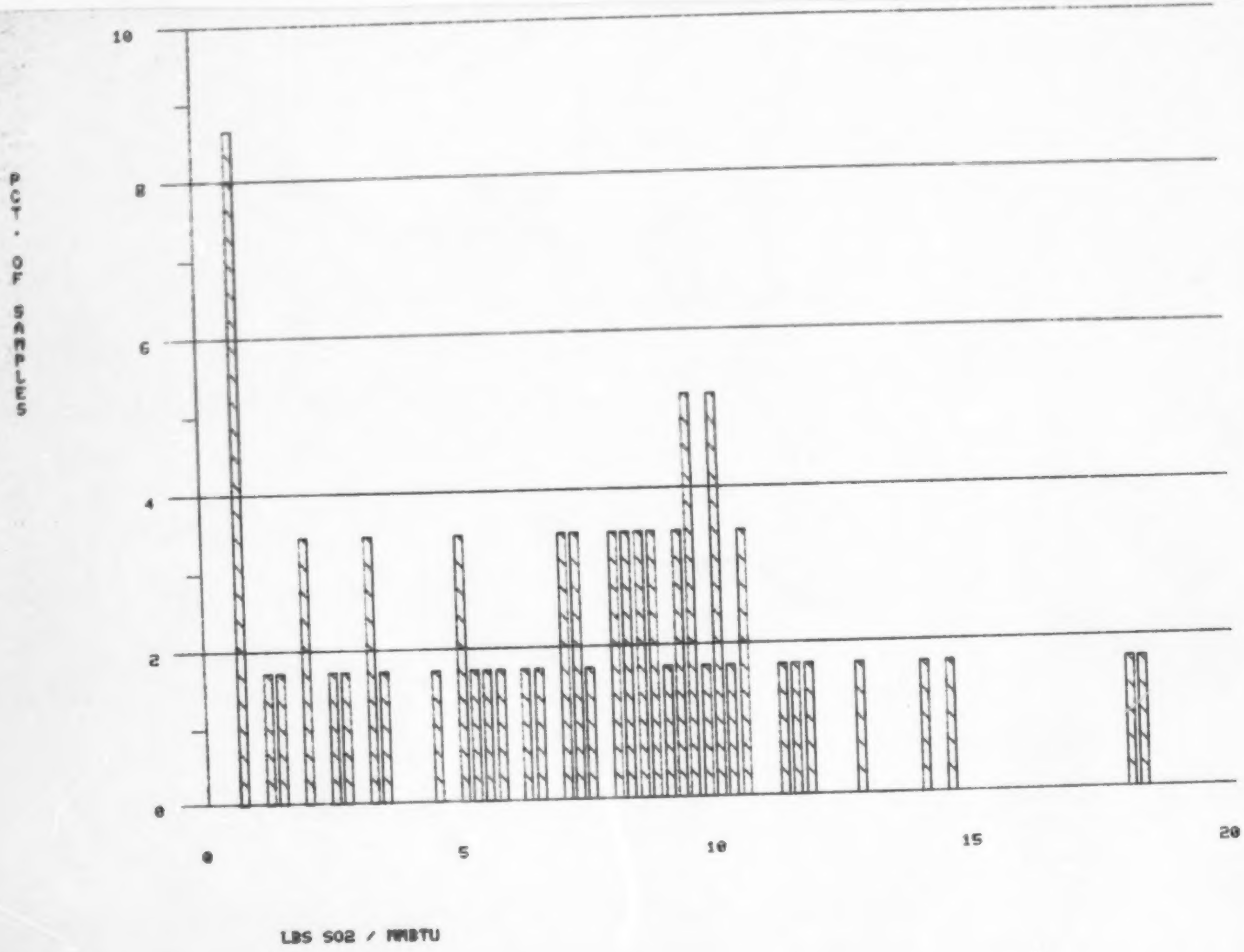


Exhibit A-15. Distribution of sulfur dioxide emissions parameter for washed coal samples from Western Midwest Region.

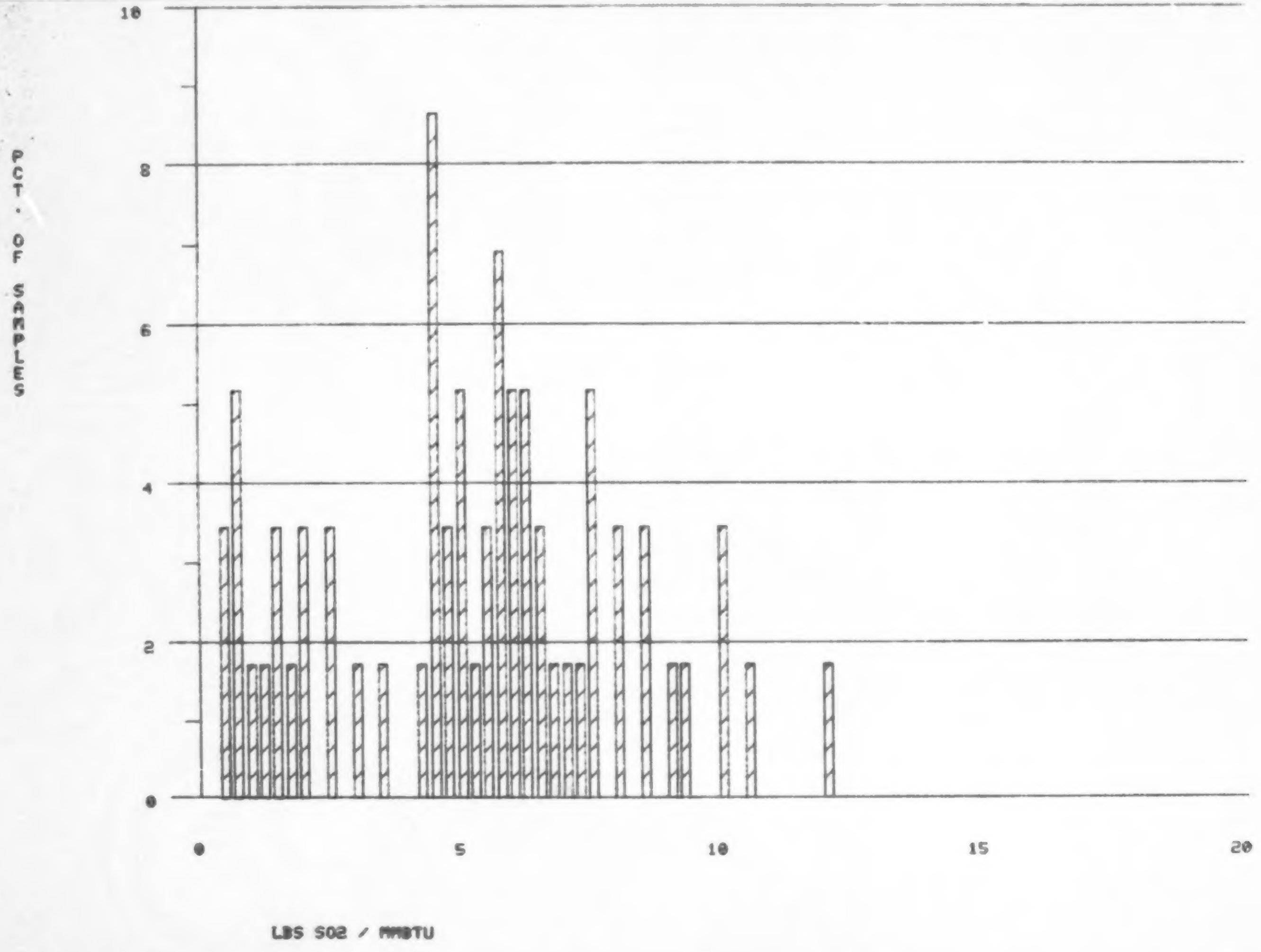


Exhibit A-16. Distribution of sulfur dioxide emissions parameter for raw and washed coal samples from Western Midwest Region.

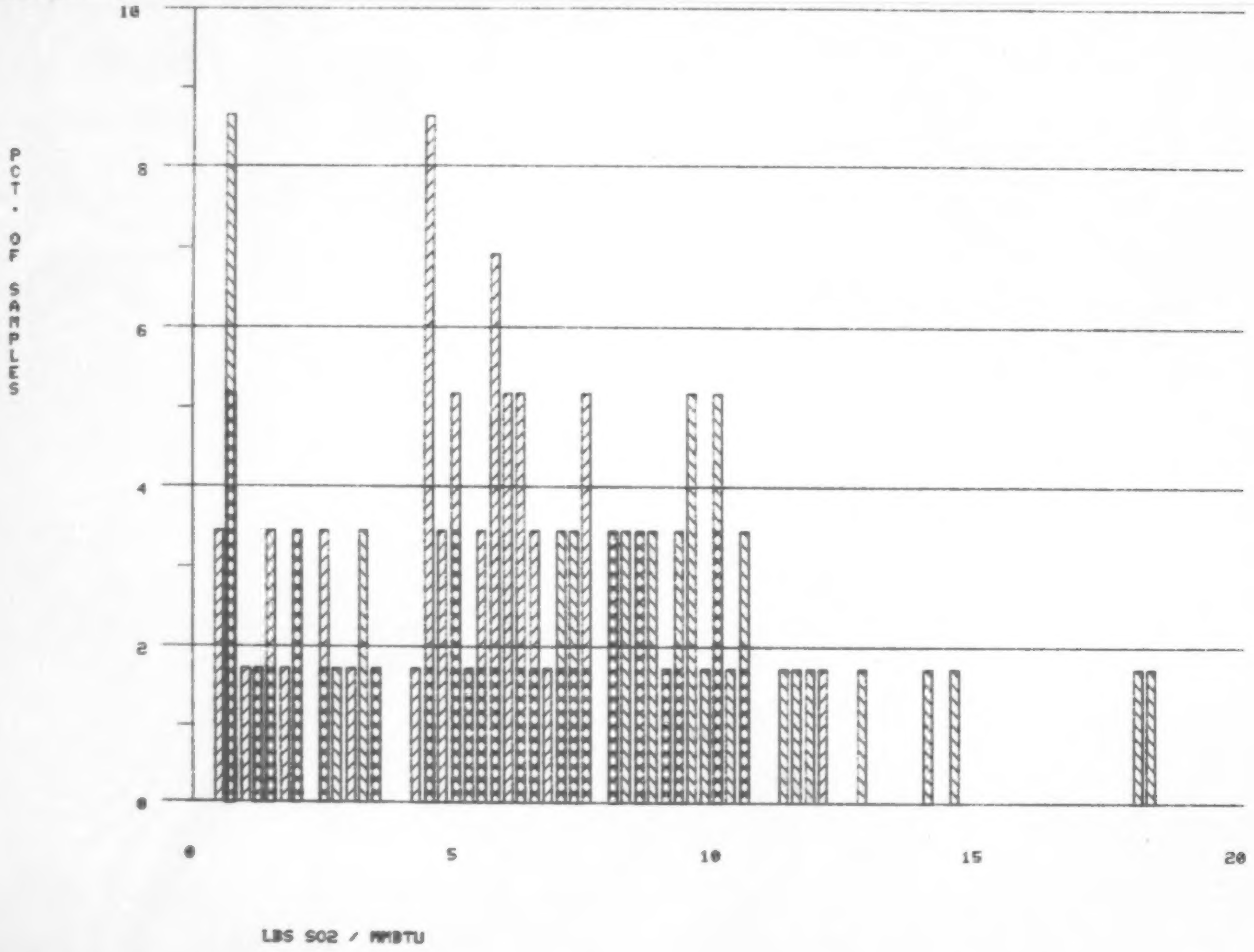


Exhibit A-17. Distribution of sulfur dioxide emissions parameters for raw coal samples from Western Region.

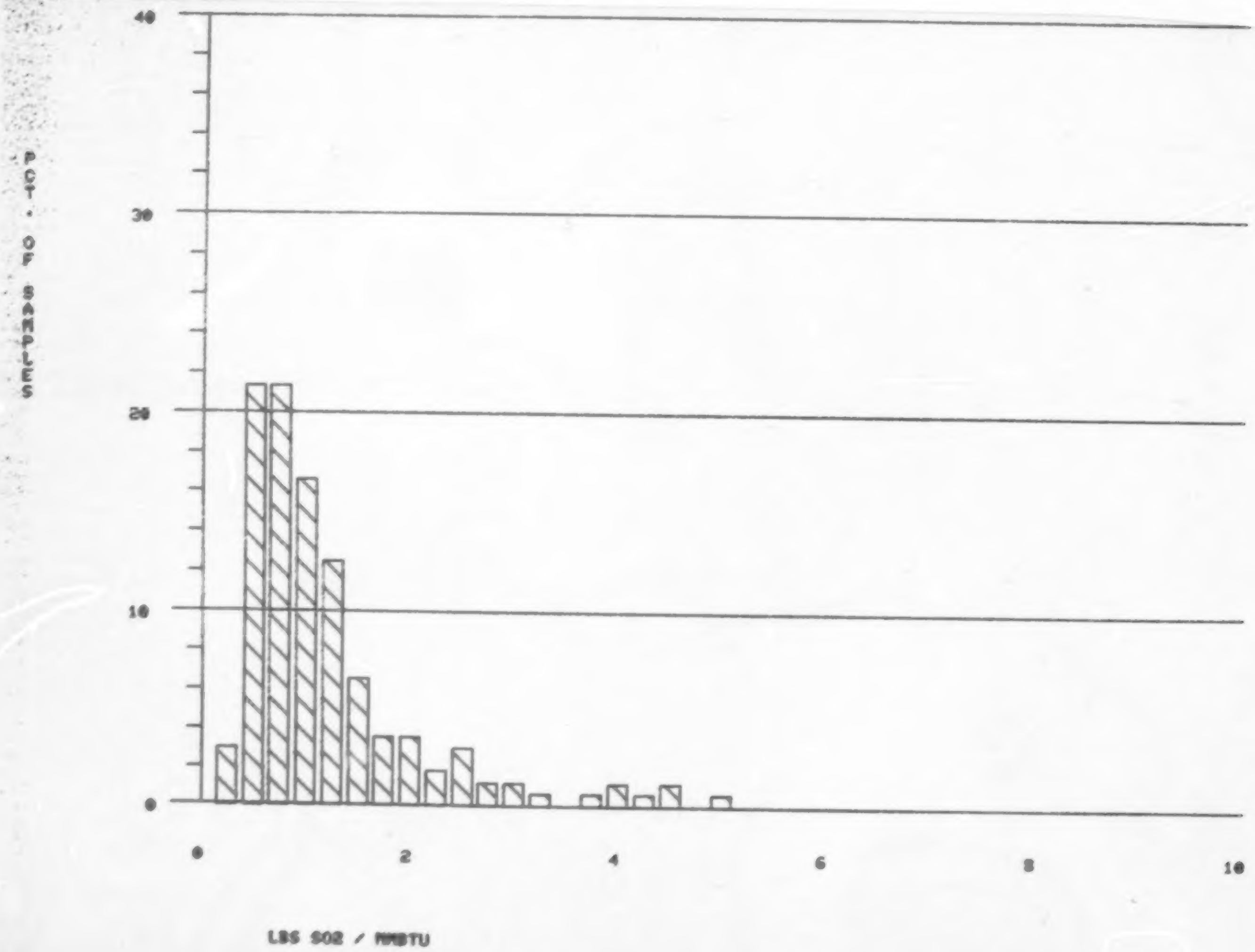


Exhibit A-18. Distribution of sulfur dioxide emissions parameter for washed coal samples from Western Region.

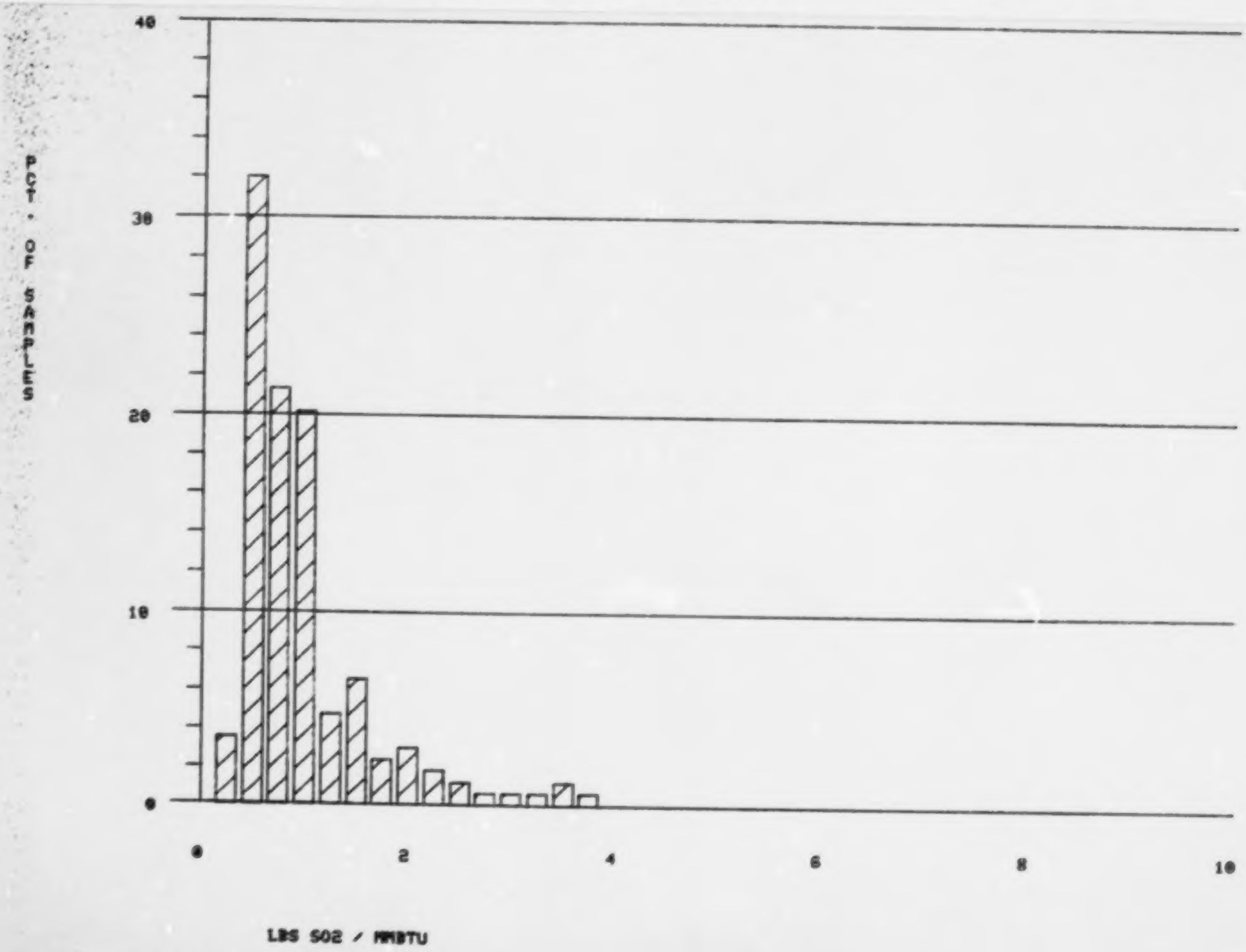


Exhibit A-19. Distribution of sulfur dioxide emissions parameter for raw and washed coal samples from Western Region.

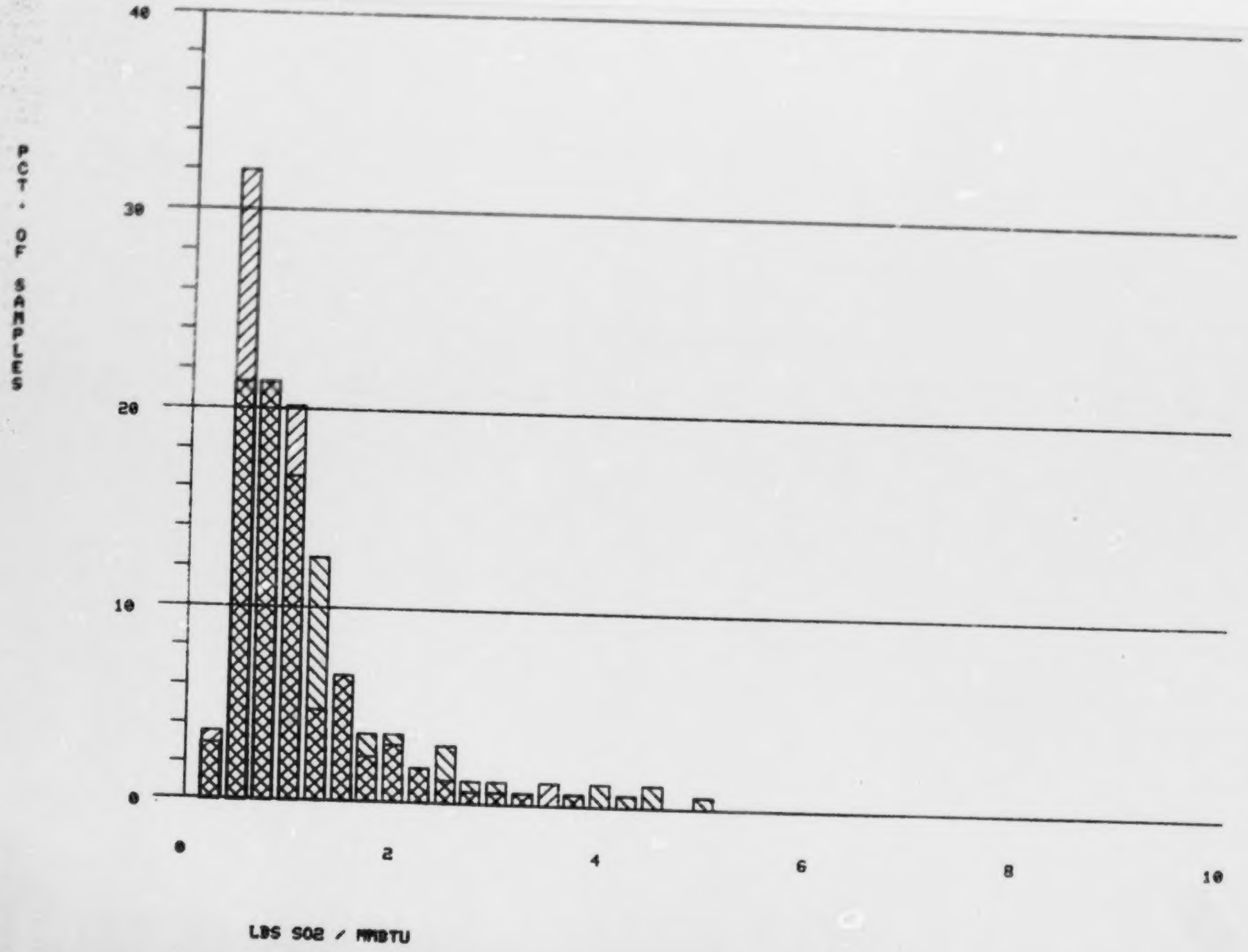


Exhibit U-1. Listing of User State Coal Sources And Potential

Exhibit A-20. Listing of user state coal sources and potential SO_2 reduction by washing.

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                                              SOUTHERN REGION

                                              USER STATE: AL
SOURCE STATE     PERCENT OF USER STATE COAL    PERCENT SULFUR    LBS. SO2/MMBTU   BTU/LB COAL    PERCENT REDUCTION    TONS SO2

    AL                   70.00                     1.41               2.35          11987.77           11.00          39351.21
    KY                   19.00                     2.55               4.40          11579.10           12.00          21072.85
    TN                    4.00                     1.84               3.02          12173.01           12.00           3201.16
    OH                    3.00                     2.13               3.66          11627.48           31.00           7179.77
    IN                    2.00                     1.74               3.16          11001.43           30.00           3783.98
    WV                    1.00                     1.79               2.90          12332.25           12.00            778.54
TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     75367.56

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:  18.1410


                                              USER STATE: FL
SOURCE STATE     PERCENT OF USER STATE COAL    PERCENT SULFUR    LBS. SO2/MMBTU   BTU/LB COAL    PERCENT REDUCTION    TONS SO2

    KY                   63.00                     2.22               3.79          11703.10           30.00          49669.55
    IL                   25.00                     2.51               4.27          11744.46           30.00          22284.89
    AL                    9.00                     2.32               3.83          12102.54           11.00           2718.94
TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     74673.38

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:   5.9250


                                              USER STATE: GA
SOURCE STATE     PERCENT OF USER STATE COAL    PERCENT SULFUR    LBS. SO2/MMBTU   BTU/LB COAL    PERCENT REDUCTION    TONS SO2

    KY                   62.00                     1.76               2.96          11879.77           30.00         125447.30
    IL                   17.00                     2.52               4.45          11314.30           30.00          49250.02
    VA                    2.00                     1.18               1.93          12215.52           12.00           1085.25
    TN                    9.00                     1.14               1.85          12311.77           12.00           4718.07
    IN                    7.00                     1.28               2.34          10929.03           30.00          10300.65
TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     190801.20

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:  19.1800


                                              USER STATE: MS
SOURCE STATE     PERCENT OF USER STATE COAL    PERCENT SULFUR    LBS. SO2/MMBTU   BTU/LB COAL    PERCENT REDUCTION    TONS SO2

    AL                   25.00                     2.27               3.69          12290.99           11.00           3292.68
    KY                   30.00                     1.86               3.29          11295.47           30.00           8829.71
    IL                   10.00                     2.57               4.26          12053.43           30.00           4066.73
    CO                   25.00                     0.55               0.96          11446.66           12.00            870.31
    UT                   10.00                     0.50               0.85          11752.72           12.00            316.48
TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     17375.91

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:   2.6400
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                                             USER STATE: NC
SOURCE STATE     PERCENT OF USER STATE COAL     PERCENT SULFUR     LBS. SO2/MMBTU   BTU/LB COAL    PERCENT REDUCTION    TONS SO2

    KY                     52.00                     0.94               1.55          12116.68           12.00          24605.71
    VA                     31.00                     0.99               1.62          12209.77           12.00          15449.04
    WV                     15.00                     0.84               1.40          11987.78           12.00           6342.71
TOTAL TONS OF SULFUR DIOXIDE REDUCTION:       46397.46

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:  20.9960


                                             USER STATE: SC
SOURCE STATE     PERCENT OF USER STATE COAL     PERCENT SULFUR     LBS. SO2/MMBTU   BTU/LB COAL    PERCENT REDUCTION    TONS SO2

    KY                     84.00                     1.32               2.13          12381.74           30.00          39125.11
    VA                     16.00                     1.27               2.05          12377.62           12.00           2868.05
TOTAL TONS OF SULFUR DIOXIDE REDUCTION:       41993.16

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:   5.8870


                                             USER STATE: TN
SOURCE STATE     PERCENT OF USER STATE COAL     PERCENT SULFUR     LBS. SO2/MMBTU   BTU/LB COAL    PERCENT REDUCTION    TONS SO2

    KY                     68.00                     2.33               4.14          11244.57           30.00         221045.40
    TN                     19.00                     1.65               2.77          11901.21           12.00          17495.00
    OH                      9.00                     3.68               6.65          11056.39           31.00          47747.13
    IL                      2.00                     2.25               3.91          11497.23           30.00           6278.11
    AL                      1.00                     1.68               2.92          11495.13           11.00            859.40
    IN                      2.00                     2.12               3.87          10944.91           30.00           5915.38
    VA                      2.00                     1.59               2.68          11853.58           12.00           1774.61
TOTAL TONS OF SULFUR DIOXIDE REDUCTION:      301115.00

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:  23.2760


GRAND TOTAL SULFUR DIOXIDE REDUCTION:      747723.70

GRAND TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:  96.0450
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                                                   MIDDLE ATLANTIC REGION

                                                     USER STATE: DL

SOURCE STATE     PERCENT OF USER STATE COAL     PERCENT SULFUR     LBS. SO2/MMBTU    BTU/LB COAL     PERCENT REDUCTION     TONS SO2

    PA                    99.00                      1.73               2.80           12344.55            31.00           10618.52

TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     10618.52

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:   1.0010


                                                     USER STATE: MD

SOURCE STATE     PERCENT OF USER STATE COAL     PERCENT SULFUR     LBS. SO2/MMBTU    BTU/LB COAL     PERCENT REDUCTION     TONS SO2

    PA                    65.00                      1.56               2.54           12270.95            31.00           32099.07
    MD                    18.00                      1.47               2.44           12036.90            31.00            8376.15
    WV                    15.00                      0.88               1.40           12558.62            12.00            1617.51
    KY                     7.00                      0.70               1.09           12830.96            12.00             600.44
    VA                     1.00                      2.00               3.18           12565.80            12.00             245.08

TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     42938.25

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:   5.1110


                                                     USER STATE: NJ

SOURCE STATE     PERCENT OF USER STATE COAL     PERCENT SULFUR     LBS. SO2/MMBTU    BTU/LB COAL     PERCENT REDUCTION     TONS SO2

    WV                    59.00                      2.11               3.29           12813.68            31.00           16808.92
    VA                    20.00                      1.26               1.85           13607.74            12.00            1317.12
    PA                    20.00                      1.21               1.88           12859.22            31.00            3267.54

TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     21393.57

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:   2.1800


                                                     USER STATE: NY

SOURCE STATE     PERCENT OF USER STATE COAL     PERCENT SULFUR     LBS. SO2/MMBTU    BTU/LB COAL     PERCENT REDUCTION     TONS SO2

    PA                    91.00                      1.84               3.01           12213.45            31.00           63800.51
    WV                     3.00                      2.46               3.75           13106.63            31.00            2812.04

TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     66612.56

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:   6.1520


                                                     USER STATE: PA

SOURCE STATE     PERCENT OF USER STATE COAL     PERCENT SULFUR     LBS. SO2/MMBTU    BTU/LB COAL     PERCENT REDUCTION     TONS SO2

    PA                    83.00                      1.97               3.27           12036.65            31.00          391531.10
    WV                    11.00                      2.54               4.10           12377.62            31.00           66903.44
    OH                     5.00                      3.41               5.89           11567.15            31.00           40826.89
                                                                                                           31.00            5770.84
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   KY                          1.00              0.98            1.49         13140.96         12.00          908.38
TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     505940.60

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:  38.6610

                                                        USER STATE: VA
SOURCE STATE     PERCENT OF USER STATE COAL     PERCENT SULFUR     LBS. SO2/MMBTU     BTU/LB COAL     PERCENT REDUCTION     TONS SO2
    VA                         51.00                  0.81              1.34           12077.24           12.00          5055.15
    KY                         34.00                  0.93              1.49           12470.51           12.00          3869.38
    WV                         15.00                  0.83              1.33           12468.49           12.00          1523.52
TOTAL TONS OF SULFUR DIOXIDE REDUCTION:      10448.05

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:   5.1040

                                                        USER STATE: WV
SOURCE STATE     PERCENT OF USER STATE COAL     PERCENT SULFUR     LBS. SO2/MMBTU     BTU/LB COAL     PERCENT REDUCTION     TONS SO2
    WV                         86.00                  2.06              3.41           12069.80           20.00        195434.80
    KY                         10.00                  0.96              1.63           11767.14           12.00          6354.17
    VA                          2.00                  1.07              1.87           11432.19           12.00          1416.45
    OH                          1.00                  0.92              1.63           11276.85           30.00          1522.35
    MD                          1.00                  1.46              2.57           11350.28           30.00          2415.91
    PA                          1.00                  1.21              2.08           11622.75           30.00          2002.22
TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     209145.90

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:  27.6070

GRAND TOTAL SULFUR DIOXIDE REDUCTION:     867097.40

GRAND TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:  85.8160
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CENTRAL REGION

USER STATE: IA

SOURCE STATE	PERCENT OF USER STATE COAL	PERCENT SULFUR	LBS. SO2/MMBTU	BTU/LB COAL	PERCENT REDUCTION	TONS SO2
IL	17.00	2.72	5.16	10531.89	30.00	32200.13
WY	69.00	0.53	1.15	9208.00	12.00	10186.50
IA	5.00	3.89	8.31	9352.67	29.00	13092.90
KY	2.00	3.10	5.38	11512.42	30.00	4317.49
CO	3.00	0.73	1.32	11049.34	12.00	610.02
OK	2.00	3.52	5.88	11960.59	29.00	4739.03

TOTAL TONS OF SULFUR DIOXIDE REDUCTION: 65146.07

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979: 11.6180

USER STATE: IL

SOURCE STATE	PERCENT OF USER STATE COAL	PERCENT SULFUR	LBS. SO2/MMBTU	BTU/LB COAL	PERCENT REDUCTION	TONS SO2
IL	51.00	3.12	5.97	10441.61	30.00	347163.90
WY	25.00	0.46	0.97	9474.88	12.00	10036.17
MT	11.00	0.45	0.97	9268.90	12.00	4319.92
CO	5.00	0.60	1.07	11203.53	12.00	2618.13
KY	4.00	1.51	2.64	11427.73	30.00	13177.91
IN	3.00	1.98	3.60	10988.79	30.00	12959.74

TOTAL TONS OF SULFUR DIOXIDE REDUCTION: 390275.90

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979: 36.4000

USER STATE: IN

SOURCE STATE	PERCENT OF USER STATE COAL	PERCENT SULFUR	LBS. SO2/MMBTU	BTU/LB COAL	PERCENT REDUCTION	TONS SO2
IN	55.00	2.94	5.45	10778.00	30.00	54256.45
IL	18.00	2.73	5.11	10674.04	30.00	16488.32
KY	12.00	3.79	6.80	11135.70	30.00	15260.25
WY	5.00	0.74	1.44	10267.31	12.00	496.60
UT	4.00	0.60	1.02	11752.73	12.00	322.12
MT	2.00	0.40	0.85	9402.18	12.00	107.37
CO	2.00	0.39	0.70	11131.50	12.00	104.69

TOTAL TONS OF SULFUR DIOXIDE REDUCTION: 87035.81

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979: 5.5980

USER STATE: KY

SOURCE STATE	PERCENT OF USER STATE COAL	PERCENT SULFUR	LBS. SO2/MMBTU	BTU/LB COAL	PERCENT REDUCTION	TONS SO2
KY	85.00	2.91	5.32	10928.70	19.00	232226.60
IN	8.00	2.80	5.07	11034.11	30.00	33205.92
VA	2.00	0.61	0.90	13541.74	12.00	723.41
IL	2.00	3.22	6.18	10410.10	30.00	9546.71
WV	2.00	0.81	1.33	12168.04	12.00	960.60
TN	1.00	1.80	3.09	11638.61	12.00	1067.33

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TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     277730.60

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:  24.7320

                                            USER STATE: MI
SOURCE STATE     PERCENT OF USER STATE COAL    PERCENT SULFUR    LBS. SO2/MMBTU   BTU/LB COAL   PERCENT REDUCTION    TONS SO2

     KY                   38.00                     0.93              1.51          12305.34          12.00          20402.03
     OH                   21.00                     2.63              4.53          11599.64          31.00          82368.69
     WV                   19.00                     2.53              4.01          12605.60          30.00          69377.88
     IL                    3.00                     3.11              5.57          11155.59          30.00          13465.68
     IN                    1.00                     3.95              7.48          10550.74          30.00           5700.91
     PA                    3.00                     2.43              3.86          12577.84          31.00          10872.13
TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     202187.30

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:  24.0790


                                            USER STATE: MO
SOURCE STATE     PERCENT OF USER STATE COAL    PERCENT SULFUR    LBS. SO2/MMBTU   BTU/LB COAL   PERCENT REDUCTION    TONS SO2

     IL                   53.00                     2.51              4.55          11021.72          30.00         172023.80
     WY                   20.00                     0.45              0.99           9081.65          12.00           4655.24
     MO                   18.00                     4.89             10.07           9702.12          30.00         113820.50
     OK                    6.00                     3.45              5.78          11925.55          29.00          25875.34
     VA                    3.00                     1.38              2.12          13005.59          12.00           2141.41
TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     318516.20

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:  21.5740


                                            USER STATE: OH
SOURCE STATE     PERCENT OF USER STATE COAL    PERCENT SULFUR    LBS. SO2/MMBTU   BTU/LB COAL   PERCENT REDUCTION    TONS SO2

     OH                   52.00                     3.70              6.78          10903.33          31.00         632773.90
     KY                   23.00                     1.25              2.21          11300.69          12.00          36601.66
     WV                   15.00                     2.06              3.56          11561.24          31.00         101625.30
     WY                    7.00                     0.50              1.24           8056.30          12.00           4455.86
     PA                    3.00                     3.11              5.24          11858.13          31.00          30684.91
     MD                    1.00                     2.50              4.22          11836.27          31.00           8222.11
     UT                    1.00                     0.54              0.98          11009.18          12.00            687.47
TOTAL TONS OF SULFUR DIOXIDE REDUCTION:     815051.30

TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:  53.1000


                                            USER STATE: WS
SOURCE STATE     PERCENT OF USER STATE COAL    PERCENT SULFUR    LBS. SO2/MMBTU   BTU/LB COAL   PERCENT REDUCTION    TONS SO2

     IL                   30.00                     2.73              4.94          11041.37          30.00          60493.51
     PA                   10.00                     2.97              4.82          12311.09          31.00          22668.44
     WY                   15.00                     0.42              1.00           8391.44          12.00           1861.34
     MT                   21.00                     0.84              1.92           8741.09          12.00           5211.75
     IN                    2.00                     4.17              7.44          11198.25          30.00           6160.14
     OH                    3.00                     3.08              5.22          11788.74          31.00           7052.41
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TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979:  12.3230

GRAND TOTAL SULFUR DIOXIDE REDUCTION:   2259391.00
GRAND TOTAL MILLIONS OF TONS OF COAL BURNED IN 1979: 189.4240
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APPENDIX B

COAL PREPARATION EQUIPMENT DATA

SECTION B.1 - COMMINUTION

Rotary Breaker --

The rotary breaker (Figure B-1) is most commonly used for primary size reduction (e.g., 6-inch top size) of deep-mined coal containing a large percentage of floor and roof material. It consists of a rotating drum or cylinder with a heavy trommel screen or perforated plate through which coal passes, and a discharge chute for refuse. Its interior has radial lifting shelves which raise the coal and then drop it to the bottom. The coal breaks by gravity impact on other coal or on the heavy screen plates. The rotary breaker thus serves a dual function: it reduces coal to a predetermined top size and it removes coarse refuse and tramp iron. The construction permits scalping of the undersize as it enters the breaker.

The rotary breaker is a rugged device, 1.8 to 3.6 m (6 to 12 ft.) in diameter with a length ranging from 1.5 to 2.5 times the diameter. It rotates at 12 to 18 rpm, and has capacities up to 1,330 kkg/h (1,500 tph) depending on the type, size, moisture content, and hardness of the feed coal and on the top size of the final product.

Single-Roll Crusher --

The single-roll crusher (Figure B-2) is one of the oldest types of comminution equipment. It can be used for both primary and secondary size reduction. It is particularly efficient in handling wet or dry friable feeds in large quantities. It consists primarily of a heavy frame on which are mounted a toothed crushing roll and a stationary breaker plate. As material enters the crusher through the feed hopper, it is struck by the teeth on the revolving roll. Some breakage occurs by impact. The rotation of the roll then carries the material into the crushing chamber formed between the breaker plate and the single roll. As the turning roll crushes the material against the stationary breaker plate, the teeth on the roll simultaneously shear the material. The discharge end of the crusher is completely open, and the sized pieces of

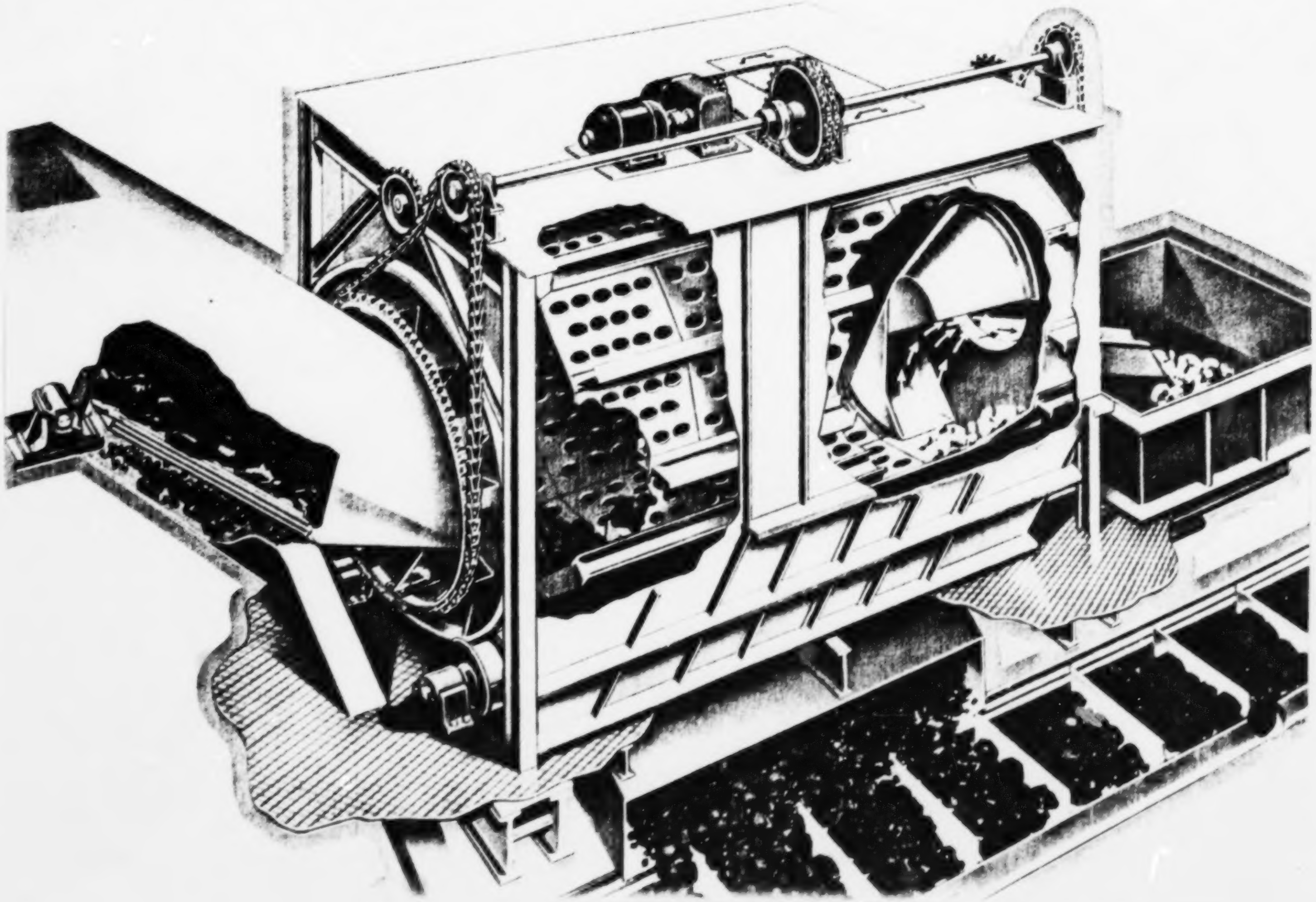

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Figure B-1. Rotary Breaker

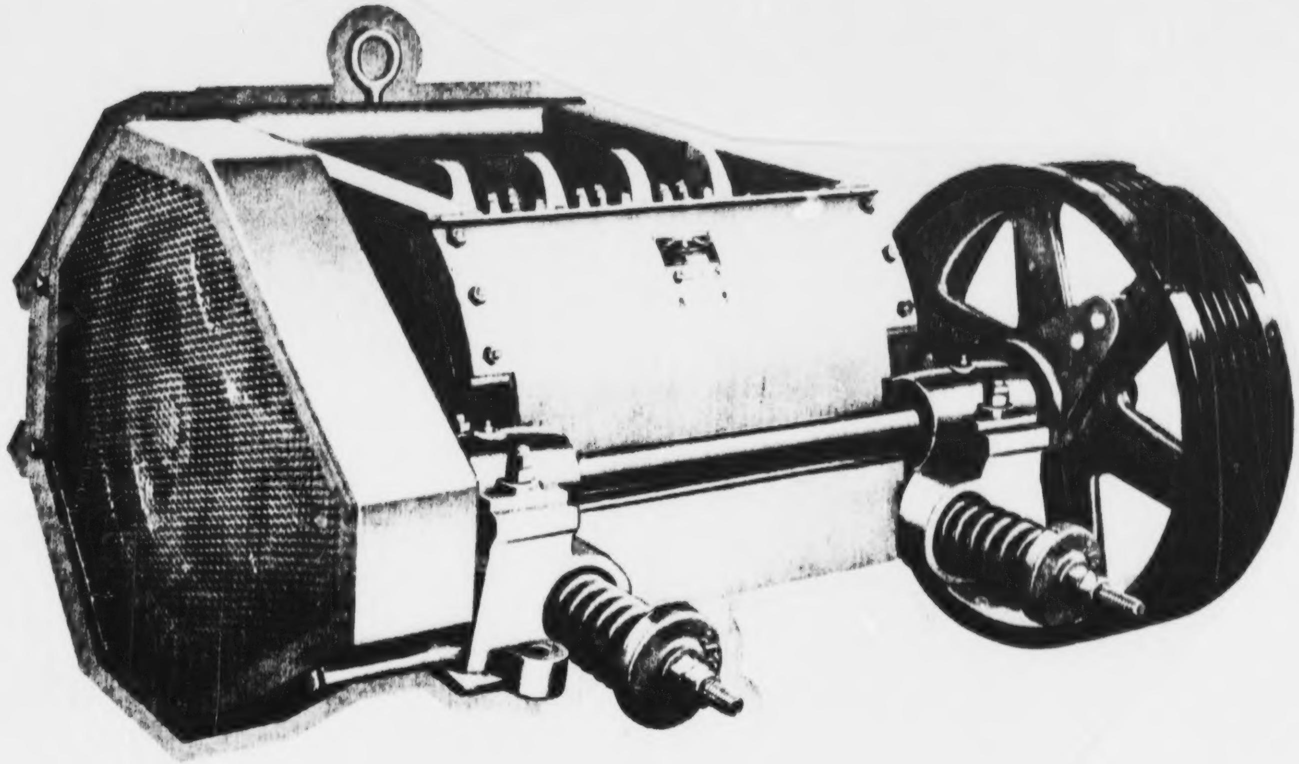

Figure B-2. Single-roll crusher.

crushed material fall through immediately. The clearance between the breaker plate and the roll determines the size of the product. This clearance is adjustable from outside the machine by a shim arrangement located near the bottom of the breaker plate. A typical single-roll crusher is capable of reducing ROM coal to 40 x 0 mm (1.5 in. x 0) without stalling.

In a double-roll crusher, two toothed rolls positioned on parallel horizontal axes turn toward each other at the same speed. Crushing is achieved by impact rather than compression, producing a relatively small amount of fines. A double-roll crusher is capable of handling ROM feed and reducing it to 31.8 x 0 mm (1 1/4 x 0 in.) without stalling. Double roll crusher capacities depend upon the size and speed of the roll, the maximum size and type of feed coal, and the product size required.

Other types of roll crushers are two-stage crushers. The two-stage crusher can be described as a combination of two crushers in series. There are two design variations of the two-stage crusher: triple-roll and four-roll crushers. In triple-roll crushers, initial crushing is performed by a roll and a curved breaker plate (as in the single-roll crusher). The second stage consists of two rolls rotating toward each other (as in the double-roll breaker). In four-roll crushers, each stage has two rolls rotating toward each other. Two stage crushers are capable of crushing coal to a product with a top size as small as 12.7 mm (0.5 in.).

Hammermill --

Hammermills crush coal by impact and attrition. Size reduction starts when hammers impact the feed material on the breaker plate. Fragments are swept into the attrition zone and further reduced at pinch points between hammers and openings in grates (cage bars). All material too large to pass through the cage bars is swept around the rotor to re-enter the impact zone for further reduction. Figure B-3 illustrates a cross-section of a hammermill.

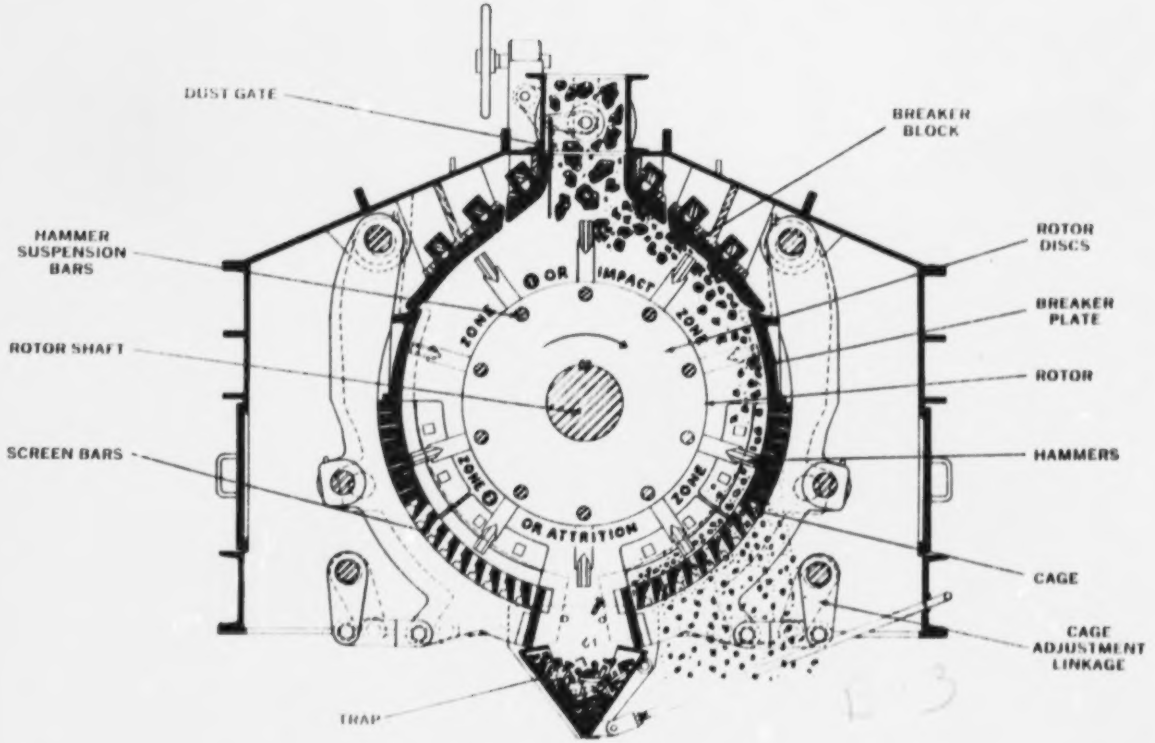
DUST GATE
BREAKER BLOCK
HAMMER SUSPENSION BARS
ROTOR DISCS
ZONE ① OR IMPACT ZONE
BREAKER PLATE
ROTOR SHAFT
ROTOR
SCREEN BARS
HAMMERS
ZONE ② OR ATTRITION ZONE
CAGE
CAGE ADJUSTMENT LINKAGE
TRAP
B3

Figure B-3. Cross-section of a hammermill.

Some manufacturers offer reversible hammermills in which the direction of rotation may be reversed to increase hammer life. Reversible mills have twin breaker blocks attached symmetrically around the top half of the rotor and twin cages attached symmetrically around the bottom half. The cage position may be adjusted to compensate for hammer wear. Cage bar spacing may be varied for adjustment of product size. These hammermills can be used for primary and secondary reduction operations. They produce material containing no oversize particles but many fines.

A variation of hammermills is ring-crushers. Ring crushers use circular rings in place of swing hammers. Size reduction is by impact and compression (rather than attrition). This crushing mechanism reduces the amount of fines in the product.

SECTION B.2, SIZING

Two basic processes take place in screening: stratification and separation. In stratification the large particles remain at the top of the layer of material and the smaller particles eventually reach the screen openings. Stratification is a desirable effect without which efficient separation could not take place.

In separation, the particles present themselves to the apertures; they are rejected if larger than the opening or pass through if smaller than the opening. Not all the particles with dimensions smaller than the screen opening are able to pass through the screen. The probability of the particles passing through the screen opening depends upon the relative size and shape of the particle with respect to the size and shape of the opening.

Screens used in coal preparation plant can be categorized as vibrating and stationary screens. They can also be grouped according to the function they perform as:

- Scalping screens. These are used to classify ROM coal prior to primary crushing. Size separations are usually made at (4 to 8 in.); dry or wet screening can be used. Capacities of scalping screens usually range between 49 and 59 kkg of coal per square meter (5 and 6 tph of coal per square foot) of screening area.

- Raw coal sizing screens. These screens classify coal from primary crushers, and they are used prior to cleaning devices to separate coarse size coal from intermediate and fine size coal. Size separations are made either dry or wet at 38.1 to 3.4 mm (1.5 in. to 6 mesh). Capacities of these screens normally range from 15 to 29 kkg of coal per square meter (1.5 to 3 tph of coal per square foot) of screening area.

- Prewet screens. These are used prior to coarse coal cleaning devices (such as heavy media vessel or jig) to provide a constant moisture coal feed (wet screening) and, at the same time, to remove smaller particles which adversely affect the performance of these devices. They have screen openings ranging from 2 to 6 mm (10 mesh to 1/4 in.).

- Desliming screens. These are used to classify fine size coal from the intermediate size coal. The feed streams to these screens are the underflows from the raw coal sizing screens and/or the prewet screens. They have screen openings of about 0.6 mm (28 mesh) and have capacities of approximately 5 kkg of coal per square meter (0.5 tons of coal per square foot) of screening area.

Two other types of screens used in coal preparation plants drain and rinse screens and dewatering screens will be discussed with the dewatering equipment.

SECTION B.3, CLEANING

Jig --

Jigs rely on the process of particle stratification due to the range of specific gravities represented by the coal and impurities. The stratification results from repeated expansion and compaction of a bed of particles by a pulsating fluid, usually water.

Pulsation in jigs can be produced by various methods, the most popular of which is by air, used in Baum jigs. The Baum jig is a "U" shaped box (Figure B-4). On one side, near the top, are perforated screen plates, that support the bed of coal. On the side opposite the screen plates is a sealed compartment where the water pulsations are initiated. This chamber is fitted with intake and exhaust valves for the admission and exit of compressed air. In the pulsation stroke the intake valve opens and water moves upward through the particle bed and causes it to expand. Water moving downward through the bed causes compaction (suction stroke). During the pulsation stroke the particles move upward in relation to their specific gravities, i.e., fragments of lighter specific gravity material move a greater distance. During the suction stroke, the exhaust valve opens and the lighter specific gravity materials descend at a rate slower than their heavier counterparts stratifying the bed. After such cycles, particles are stratified within the bed.

Aside from the mechanical system designed to produce and control the pulsation-suction cycles, there are two other systems within the typical jig. They are:

- A feed system, and
- A system to separate the stratified bed into product and refuse and to remove each of these fractions.

The jig box is divided horizontally into compartments by fixed vertical weirs designed to control the lateral movement of the coal bed. Each compartment is actually a jig within a jig; each one has the means for individual discharge of refuse and clean coal, either to the next compartment or to a conveyor.

The presence of a large percentage of near gravity material adversely affects the efficiency of the jig. For this reason, jigs are usually designed to produce a middling fraction (consisting of the near gravity material) in addition to the clean coal and refuse. The middlings can be

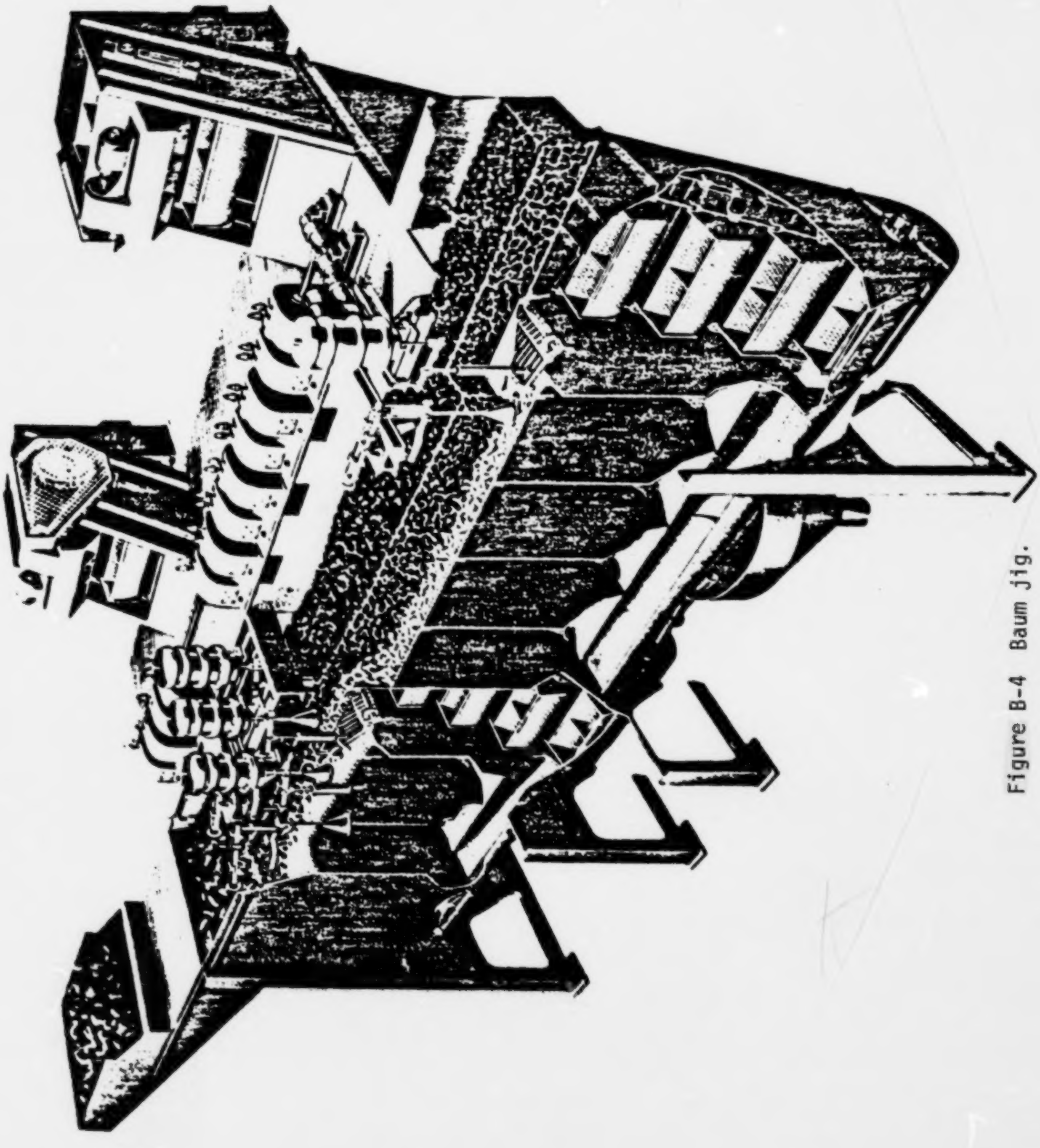

Figure B-4 Baum jig.

marketed as is, crushed and recycled to the jig or cleaned in another device. Jigs can clean up to 636 kkg/hr (700 tph) of feed coal.

A new advancement in jigging technology is the development of the Batac jig. Batac jigs clean fine as well as coarse coal. Batac jigs have capacities up to 545 kkg/hr (600 tph) for 13 mm x 0 (0.5 in. x 0 size coal. Pulsations in the Batac jig are produced directly beneath a feldspar bed screen in multiple, independently controlled chambers that are uniformly distributed throughout the jig. The first three Batac jig units commissioned in the U.S. (in 1975 and 1976) all clean fine size coal.

Concentrating Table --

Concentrating tables (e.g., Deister Tables) are used in the U.S. to clean 1.0 cm to 0.6 cm x 0 (3/8 in. to 1/4 in. x 0) coal. However, it is becoming common to deslime feed coal at 0.30 or 0.15 mm (48 or 100 mesh) before tabling. Concentrating tables flow a slurry of coal and water over an inclined riffled deck which shakes rapidly, effecting a separation of the particles--by size and specific gravity. As the coal-particles are introduced in the table, they stratify in layers behind the riffles because of the action of the table and the gravitational motion of the particles. Layers of coal then travel downward as a result of cross-flowing water. Low density particles ride over the riffles and report to the clean-coal side of the table. High-density particles are carried behind the riffles to the refuse end of the table. Furthermore, separation of particles due to size differences also occurs: small particles are carried by the water toward the refuse end. Distribution of table products by particle size and specific gravity is shown in Figure B-5.

The adjustable operating parameters for a given feed coal include the amplitude and frequency of the stroke, and the end elevation (the relative height of the feed to the refuse end of the table). The amplitude and frequency of the stroke are decreased as the amount of

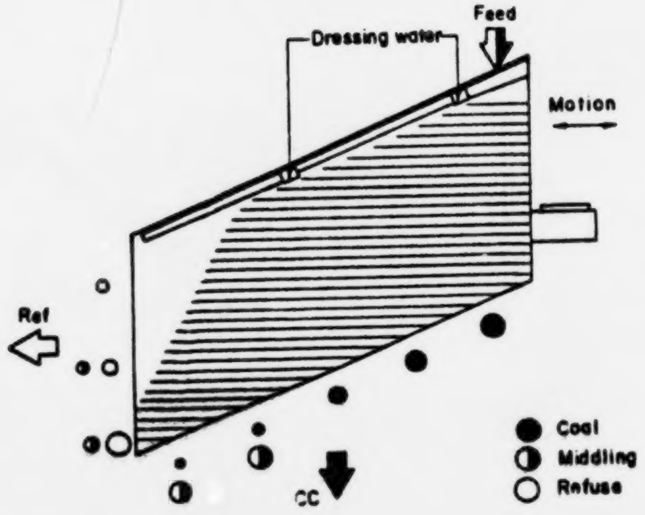
Feed
Dressing water
Motion
Ref
CC
Coal
Middling
Refuse

Figure B-5. Concentrating table - top view.

near-gravity material in the feed increases. For example, a 1.0 cm x 0 (3/8 in. x 0) coal would require a stroke amplitude of about 1.9 cm (3/4 in.), a frequency of 275 strokes per minute, and an elevation of 8 to 10 cm (3 to 4 inches).

Since 1957, multiple-deck concentrating tables have been introduced into the coal preparation industry in the U.S. These units have the advantage of occupying less floor space than the single-deck units. The twin-deck unit can handle 27 kkg/h (30 tph) of 19.1 or 12.7 mm (3/4 or 1/2 in.) coal, and 23 kkg/h (25 tph) of 1.0 cm x 0 (3/8 in. x 0) coal with a power requirement of approximately 3 hp.

Hydrocyclone --

Hydrocyclones separate clean coal from refuse using water as the medium. The hydrocyclone body consists of a short cylindrical section, attached to an inverted, truncated conical section (Figure B-6). The overflow orifice (the vortex finder) is centrally located at the top of the cyclone, and the underflow orifice is at the apex of the conical section. The feed coal is slurried and tangentially introduced through the inlet nozzle mounted on the cylindrical section, where the centrifugal forces act on the particles in proportion to their mass. The centrifugal forces acting on the particles increase with decreasing radii, as the slurry moves downward into the conical section of the cyclone. Higher specific gravity particles (primarily heavy mineral matter and pyrite) of a given size move outward toward the descending vortex more rapidly than the less-dense particles. As the less-dense particles approach the apex of the cone, they are drawn into the upward-flow vortex where they exit through the overflow and report to the clean coal. The denser particles, which flow along the cyclone wall, report to the underflow orifice as refuse.

In the United States, hydrocyclones are generally used to clean fine size coal, especially when the coal is oxidized and cannot be treated in flotation equipment. Hydrocyclones are effective on coal as coarse as

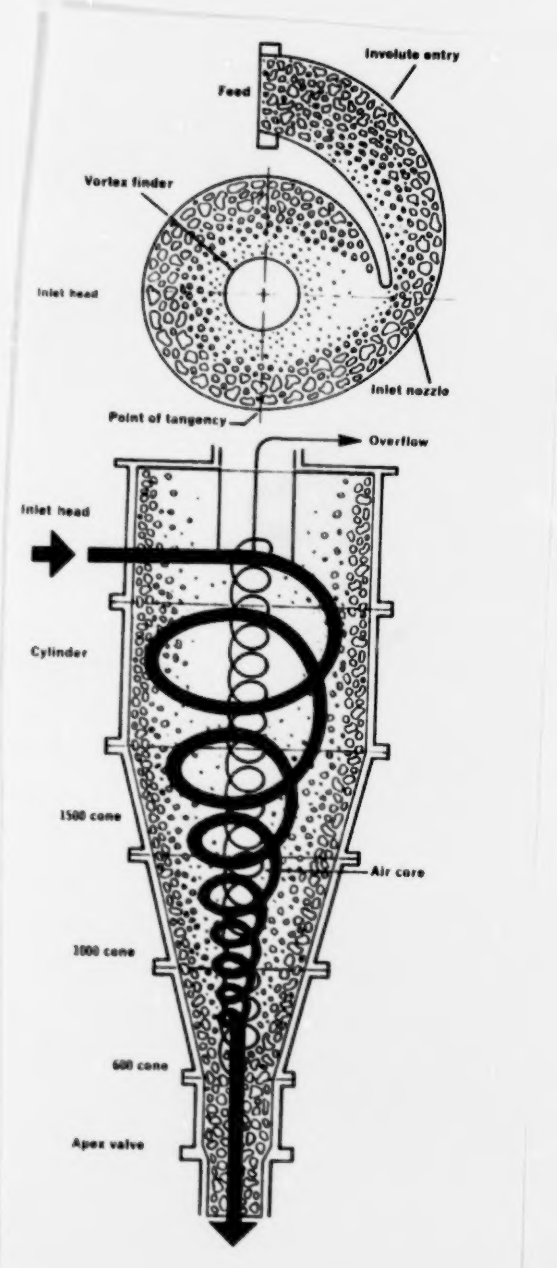
Involute entry
Feed
Vortex finder
Inlet head
Inlet nozzle
Point of tangency
Overflow
Inlet head
Cylinder
1500 cone
Air core
1000 cone
600 cone
Apex valve

Figure B-6. Schematic of hydrocyclone.

6.4 mm (0.25 inch). Furthermore, hydrocyclones can be used as a scalping unit ahead of cleaning equipment such as concentrating tables.

Because separation efficiencies of hydrocyclones are not as sharp as other coal cleaning devices, a two-stage or even three-stage hydrocyclone treatment is effective in improving the overall efficiency of the circuit. In the two-stage treatment, the underflow product (refuse) from the primary hydrocyclone is the feed to the second cyclone. The overflow from the secondary hydrocyclone joins the washed coal for the primary unit to form the final washed-coal product; the refuse from the secondary hydrocyclone is the final refuse material. In three-stage processing the procedure is repeated between a second and third hydrocyclone.

The specific gravity of separation in a hydrocyclone can be adjusted by varying the orifice diameter (i.e., diameter of the vortex finder and apex orifice) or the length of the vortex finder. A lower value for the specific gravity of separation can be obtained by reducing the diameter or length of the vortex finder, or increasing the diameter of the apex orifice.

Hydrocyclones require less space than concentrating tables or jigs, but use more water and power. Typical solids flowrate and concentration in the feed slurry to hydrocyclones are 5.4 kkg/h/unit (6 tph/unit) and 10 percent (by weight), respectively, for a maximum top size of 0.2 cm (10 mesh), and 6.3 kkg/h/unit (70 tph/unit) and 20 percent for a maximum top size of 1.9 cm (3/4 inch).

Froth Flotation Cells --

Froth flotation is a physical-chemical process used in coal preparation plants for cleaning 1.18 to 0.30 mm (14 to 48 mesh) top size coal. The important parameter in flotation chemistry is the surface characteristics of the coal particle. As a result, oxidized coals and high volatile coals are not amenable to flotation. This process operates by selective adhesion to air of some solids and the simultaneous adhesion to water of other solids (i.e., wettability of constituents in raw coal). Separation of coal from coal waste occurs as finely disseminated air bubbles are dispersed throughout a coal-water slurry. The coal particles in the slurry adhere to the air bubbles and are transported to the free surface of the pulp. These bubbles and their attached coal particles, commonly referred to as froth, are then removed; the ash and sulfur bearing material remain in suspension and are passed through the cells (Figure B-7).

The chemical process of bubble adhesion can be selectively modified by the addition of certain reagents. These reagents enhance either the floating characteristics of coals or the wetting characteristics (hydrophilic quality) of the waste material. Reagents such as methylisobutyl carbinol (MIBC) or kerosene are used to stabilize the froth, allowing sufficient time for removal of the floated coal.

Flotation cells are usually grouped in a bank of 4 or 5 cells. The number of cells determines the particle retention time while the size of each cell determines the amount of coal handled. Flotation cells are normally operated at pulp densities of 3 to 20% solids. The size consist of the feed is the main factor influencing the percent solids at which maximum efficiency can be achieved. The pH of the slurry water has an effect on the recovery and quality of the floated coal. The optimum pH for maximum recovery is between 6 and 7.5.

Dense-Medium Vessel --

Dense-medium vessels are the most efficient coarse coal 20 cm x 1 cm (8 in. x 3/8 in.) cleaning device used in the coal preparation industry today. Separation of clean coal from its impurities in dense-medium vessels involves immersing the feed coal in a fluid having a density intermediate between the clean coal and the reject. The most commonly used fluid is a mixture of finely ground magnetite (minus 325 mesh) dispersed in water. The specific gravity of the medium is adjusted by the quantity of magnetite added.

As the feed is introduced into the vessel, coal particles lighter than the medium float, and those that are heavier sink. In one type of

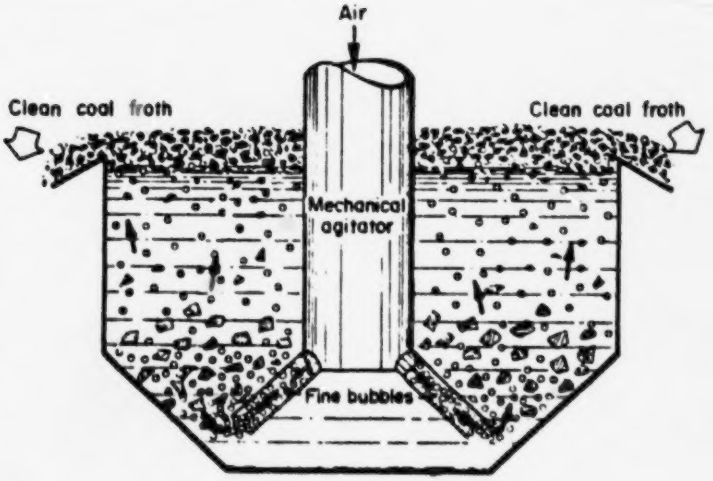
Air
Clean coal froth
Clean coal froth
Mechanical agitator
Fine bubbles

Figure B-7. Froth flotation cell.

dense-medium vessel, where a constant density is maintained, a single conveyor skims off the float product and on its return run removes the sink. The product and refuse are discharged at the opposite ends of the vessel. In another type of dense-medium vessel (Figure B-8), where a gradually increasing density from surface to bottom is maintained, two conveyors are used: the first one is to skim off the float; the second one is to collect the middlings and the refuse (discharged at opposite ends of the vessel).

After clean coal is separated from the refuse (and middlings), the medium adhering to the separated products is removed by water spraying and rinsing. Because the medium removed from the products is diluted by the spray and rinse water, it is concentrated in magnetite separators before being reintroduced into the dense-medium vessel.

Cleaning of coal in dense-medium vessels can be performed efficiently if the feed is sized and wetted. The top size of the feed coal must be controlled by crushing the ROM coal in such equipment as rotary breakers. In addition, fines must be removed before cleaning because they increase the viscosity of the medium and affect the efficiency of the separation. The presized coal must also be wetted before cleaning (1) to prevent "rafting" of dry particles in the dense-medium vessel and (2) to supply the system with a known and constant amount of water in the feed for better control of the specific gravity in the dense-medium vessel.

Dense-medium vessels can handle up to 430 kkg/h (475 tph) of raw feed depending on the size range and the ratio of float coal to sink material in the feed.

Dense-Medium Cyclone --

Dense-medium cyclones are the most efficient devices available for cleaning intermediate size coal. They can make precise separations of coals containing a high percentage of near-gravity material.

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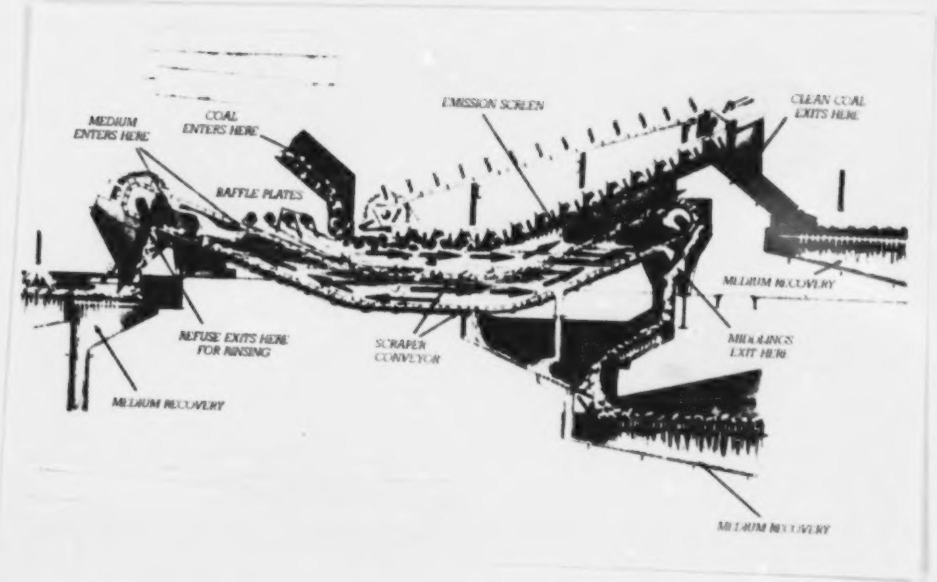
MEDIUM ENTERS HERE
COAL ENTERS HERE
BAFFLE PLATES
EMISSION SCREEN
CLEAN COAL EXITS HERE
MEDIUM RECOVERY
MIDDLINGS EXIT HERE
SCRAPER CONVEYOR
REFUSE EXITS HERE FOR RINSING
MEDIUM RECOVERY
MEDIUM RECOVERY

Figure B-8. Dense medium vessel.

Dense-medium cyclones have a more acute cone angle and a shorter vortex finder than hydrocyclones. The operational principle of dense-medium cyclones is the same as that of hydrocyclones. To achieve a gravimetric classification in a dense-medium cyclone, the water is made more dense by the addition of finely-ground magnetite. The result is that particles having a higher specific gravity are forced to the perimeter of the cone and passed out through the apex as refuse, while the particles of lesser specific gravity remain near the vortex finder and pass out through the top of the cone as cleaned coal. Cyclones for dense media operation are 30 to 76 cm (12 to 30 in.) in diameter and have high capacities. A 66 cm (26 in.) cyclone can process up to 108 kkg/h (120 tph) of feed.

In a typical dense-medium cyclone circuit, the overflow and underflow streams from the dense-medium cyclone are dewatered by their respective sieve bends and drain-and-rinse screens. The dense medium is collected in a sump, and the dilute medium is treated in a magnetic separator for magnetite recovery. The recovered magnetite is returned to the sump.

In a more advanced system for processing dilute medium, the load on the magnetic separator is greatly reduced by separating the coarse magnetite from the fine magnetite in a cyclone classifier. Only the coarse magnetite from the cyclone underflow is conveyed to a magnetite separator. The fine magnetite from the cyclone overflow and the coarse magnetite from the magnetic separator are concentrated in a thickener, then pumped to the dense-medium sump.

Air Jig --

Air jigs use air as the separation medium, and are effective when small amounts of beneficiation are required. Air jigs function best in the 1.70 to 1.90 specific gravity range and have capacities up to 91 kkg/h (100 tph) to upgrade 1.9 cm x 0 (3/4 in. x 0) coal.

In an air jig (Figure B-9), the feed particles are stratified by of pulsating air currents: coal at the top and refuse at the bottom. After

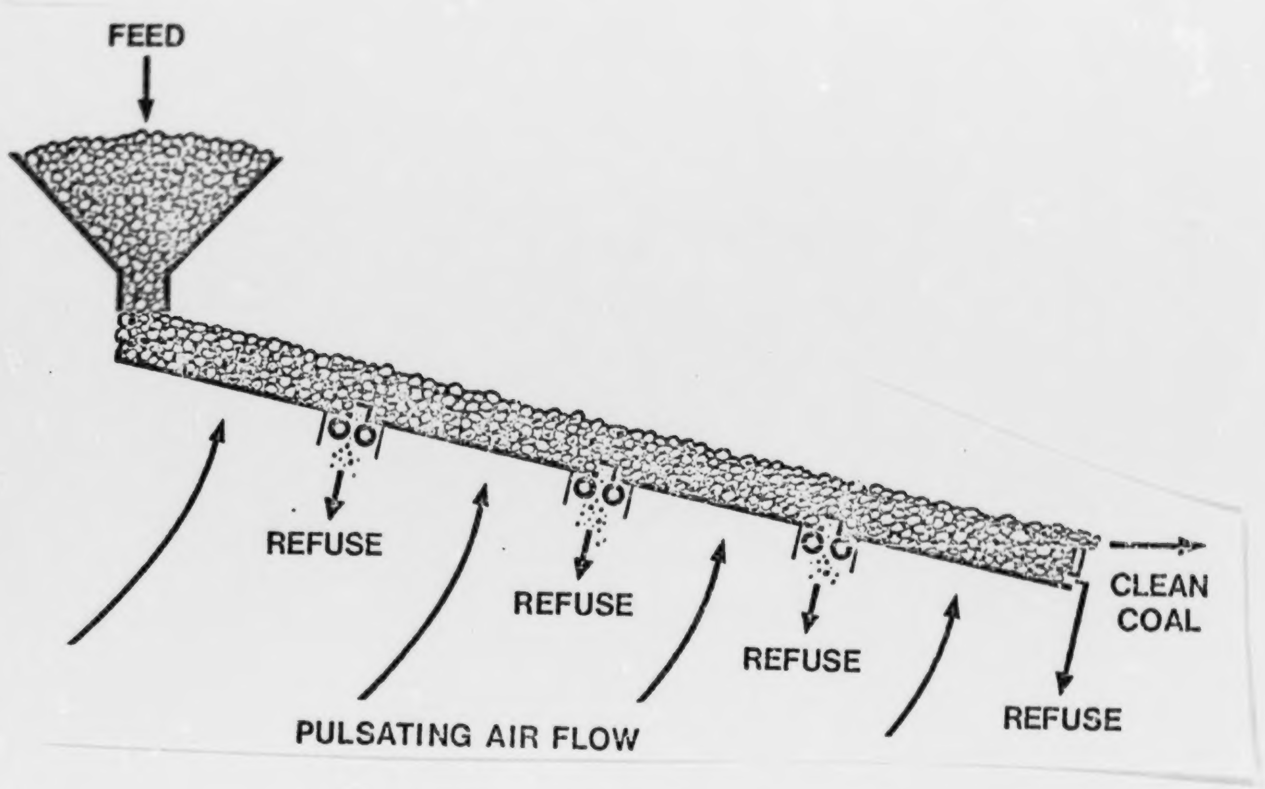
FEED
REFUSE
REFUSE
REFUSE
CLEAN COAL
REFUSE
PULSATING AIR FLOW

Figure B-9. Air jig.

the layer of refuse is formed, it travels forward into wells from which it is drawn by means of adjustable-speed rollers and removed by screw conveyors. The upper layer of coal continues to travel over the slowly moving bed and is removed at the lower end. Dust created by the pulsating air is removed by a cyclone and added to the clean coal stream.

SECTION B.4

Dewatering Screens --

Dewatering screens can be either vibrating or stationary. Vibrating, single deck screens are generally used to dewater coal coarser than 0.64 cm (1/4 in.). The surface moisture content from the vibrating screen varies with the coal size range. For example, vibrating screens can reduce the surface moisture of 10.2 x 1.0 cm. (4 x 3/8 in.) coal to 2 percent. For a particle size range of 9.5 x 0.6 mm (3/8 in. x 28 mesh), however, the moisture content of the screened coal would be approximately 12 percent.

Two of the commonly used stationary screens in coal preparation plants today are sieve bends and vorsivs. The sieve bend is a stationary wedge bar screen with the bars oriented at right angles to and across the line of flow. The screening surface is commonly curved in a 60 degree concave arc at a radius of 51 to 152 cm (20 to 60 in.). The sieve bend is used for the primary dewatering of the fine coal slurry ahead of vibrating screens and centrifuges to reduce the water load on these latter devices. It can reduce the moisture content of 0.64 cm x 0 (0.25 in. x 0) coal to 35 to 40 percent, and (28 mesh x 0) coal to 50 to 60 percent.

Dewatering of solids by the vorsiv is accomplished by the spiraling or vortex flow of the slurry over a stationary inverted cone-shaped wire screen. To date, the most popular applications of the vorsiv in the U.S. have been as a dewatering device ahead of centrifuges, as a desliming device ahead of concentrating tables, and as a load reducer ahead of thickeners and flotation cells. The vorsiv has processed feeds of minus

9.53 mm (3/8 in.) particles in slurries ranging from 10 to 30 percent solids, with flow rates up to 12,000 1/min (3,200 gal/min).

Thickening Cyclones --

Thickening cyclones are used as primary dewatering devices. In appearance, thickening cyclones differ from hydrocyclones with their short bottom. They can reduce feed slurries containing 8 to 15 percent solids to a stream containing 40 to 60 percent solids.

Thickeners --

Thickeners are sedimentation vessels used as primary dewatering devices. Diameters of thickeners used in coal preparation plants vary between 0.6 and 46 m (2 to 150 ft). The solids in the feed pulp seldom exceed 8 to 15 percent, while the concentration of solids in the discharge is 30 to 40 percent.

Centrifuges --

Centrifuges are devices that use centrifugal force for removing the surface moisture of coal. Centrifuges generally receive feed sizes from 3.75 cm to 0 (1.5 in. to 0). The types of centrifuges used in modern coal preparation plants are classified as solid bowl, screen bowl and vibrating basket centrifuges.

Solid bowl centrifuges have been principally used to dewater fine coal refuse (e.g., 30 mesh x 0) from the thickener underflow at capacities ranging from 9 to 27 kkg/h (10 to 30 tph). Screen bowl centrifuges, however, can also handle dilute coal slurries directly from cleaning equipment such as concentrating tables or froth flotation cells. Typical screen bowl centrifuges, having capacities up to 45 kkg/h (50 tph), can dewater flotation froths (containing 18 to 30 percent solids) to produce a product with approximately 17 percent moisture content. Vibrating basket centrifuges treat coarser (i.e., + 28 mesh) coal. Capacities of vibrating basket centrifuges can reach 320 kkg/h (350 tph).

Filters --

Filters are used to dewater froth flotation concentrates and fine coal slurries from thickeners. Filters process a slurry suspension containing a high percentage of solids and remove the water to produce a wet cake of coal particles ranging from 20 to 30 percent moisture. The most common type of filters used in coal preparation plants is the disc type. The disc filter consists of a number of round, disc-shaped filter sections on a rigid, hollow rotating shaft. Each filter section is composed of several wedge-shaped sectors. As vacuum is applied to the portion of the disc that is submerged into the slurry tank, a cake of fine coal forms on the filter surface. The filter cake is removed by positive pressure when the lower portion of the rotating discs is lifted out of the slurry tank. Disc filters can process a fine coal slurry containing 30 percent solids to produce a filter cake containing 18 to 28 percent moisture at rates ranging from 40 to 60 kkg/h (48 to 70 tph).

Thermal Driers --

Thermal driers use heat to evaporate surface moisture from the coal. The two types of thermal driers used in coal preparation plants are the direct type and the indirect type. Direct heat driers put thermal transfer agents (hot gases) in direct contact with the coal. The most common type of direct heat drier is the fluidized bed drier, that bed dryers can reduce the surface moisture from 11.5 to 3 percent for a coal feed rate of 47 kkg/h (52 tph). Other types of direct heat driers include multilouver, rotary, and suspension (or flash) driers.

In indirect heat drying, the coal being processed never comes into contact with the heat transfer agent (usually hot oil, but sometimes steam or hot water). Indirect heat exchangers are usually jacketed conveyors, some have helix screws while others are equipped with fins, paddles, or discs. The thermal fluid circulates through both the jacket and the screws.

APPENDIX C

COST OF PLANT ITEMS, F.O.B. SUPPLIER, BASIS JANUARY 1982

Costing Basis For Major Cleaning Plant Items

a) Crusher Costs

For crushing 3 or 4 inch to 1-1/2 inch coal
using double roll crusher

Size (Roll dia. x length)	Capacity (tph)	Cost
24 in. x 72 in.	450	$48,000
24 in. x 60 in.	375	$44,000
24 in. x 48 in.	300	$40,000
24 in. x 36 in.	225	$37,000

For crushing 3 or 4 inch to 3/8 inch coal
using triple roll crusher

Size (Roll dia. x length)	Capacity (tph)	Cost
18 in. x 72 in.	188	$58,000
18 in. x 60 in.	157	$53,000
18 in. x 48 in.	125	$48,000
18 in. x 36 in.	94	$46,000

b) Coal Screen Costs

Stationary (Inclined) Single Deck	$200/ft^2
Stationary (Inclined) Double Deck	$230/ft^2(of 1 deck)
Vibrating Single Deck	$300/ft^2
Vibrating Double Deck	$400/ft^2(of 1 deck)

Add $2,000 per screen for wash heads and piping when screens are used for drain and use duty.

Sizing based on data contained in "Coal Preparation," 4th Edition (Joseph W. Leonard editor, published by The American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., 1979) and material published by Weserhutte A. G.

c) Heavy Medium Vessel

Estimates are based on commercially available units and a conservative input capacity of 16 tph per foot of feed weir

- Unit with 14 foot weir and 15 horsepower motor - cost $60,000
- Unit with 5 foot weir and 10 horsepower motor - cost $41,000

d) Jigs for Coarse Size Coal (Water Only)

Estimates are based on commercially available units. Ratings are based on a maximum near gravity material of 7.5%. Prices include all motors, drives, blowers, and start-up assistance.

Unit	Jigging Area (ft^2)	Capacity (tph)	Cost
1	72	288	$172,000
2	105	420	$195,000
3	126	504	$220,000
4	147	588	$235,000
5	168	672	$265,000

e) Heavy Media Cyclones

Dia.	Handling Capacity	Max Feed Size (in)	Cost
14	400-500 gpm (30-40 tph)	1/2	$ 5,600
20	600-700 gpm (50-60 tph)	1	$ 6,500
24	900-1050 gpm (75-85 tph)	1-1/2	$ 7,300
28	1150-1250 gpm (110-125 tph)	2	$10,500

Units have equal capabilities on feed sizes less than indicated maximum and greater than 28 mesh.

f) Jigs for Intermediate Size Coal (Water Only)

Estimates are based on past data on commercially advertized units. Ratings are conservatively based on 3/8 inch by 28 mesh feed. Prices include Jig, air supply blower, control air compressor, and refuse and middlings disposal elevators.

Unit	Approx. Jigging Area (ft^2)	Capacity (tph)	Estimated Cost
1	195	255	$780,000
2	260	340	$820,000
3	325	425	$854,000
4	385	500	$900,000

g) Water-Only Cyclones

Diameter	Nominal Capacity	Max Feed Size (in.)	Cost
8	130 gpm (5 tph)	3/8	$ 3,500
12	300 gpm (16 tph)	28 Mesh	$ 4,500
12	400 gpm (16 tph)	5/8	$ 4,500
24	1820 gpm (68 tph)	1-1/4	$11,800

h) Concentrating Table

Basis - twin deck table (128 ft^2/deck)

Cost - $29,000 per table and distributor

Capacity per twin deck unit

Feed	Capacity (tph)
3/4 in. x 0	30
1/4 in. x 0	25
8M x 200M	15

Minimum effective specific gravity - 1.45.

Above capacity values are based on less than 20 percent rejects.

i) Froth Flotation Cells

Basis: 4 minutes effective residence time
5 percent slurry solid concentrate equivalent

At 1 tph solid throughput, the effective throughput in 4 minutes is 1/15 or 0.06667 tons.

At 5 percent solid concentrate, the slurry associated with 0.06667 tons of solids is essentially 1.333 tons or 2666.7 pounds.

2666.7 pounds of slurry at 62 pounds per ft^3 occupies 43 ft^3. In other words, 43 ft^3 cell capacity is required per pound of coal throughput per hour.

Tons Per Hour	Total Cell Capacity (ft^3)	Cost
10	430	$ 43,000
20	860	$ 54,000
35	1505	$ 68,000
50	2150	$ 86,300
80	3440	$134,000

The cost includes cells, automatic level control, chemical feeder, and motor.

j) Centrifuges

Cost $33,700

Feed	tph
3/8 in. x 28M	80
1/4 in. x 28M	60
1/8 in. x 28M	50
1/16 in. x 28M	35

Cost $35,800

Feed	tph
3 in. x 1/4 in.	200
2 in. x 1/4 in.	190
1-1/2 in. x 1/4 in.	180
1 in. x 1/4 in.	160
2 in. x 0 (28M)	160
1-1/2 in. x 0 (28M)	150
1/2 in. x 1/4 in.	140
1 in. x 0 (28M)	140
1/2 in. x 0 (28M)	125
3/8 in. x 0 (28M)	115
1/4 in. x 0 (28M)	110

Cost $60,000

Feed	tph
3 in. x 1/4 in.	325
2 in. x 1/4 in.	315
1-1/2 in. x 1/4 in.	300
1 in. x 1/4 in.	270
2 in. x 0 (28M)	270
1-1/2 in. x 0 (28M)	255
1/2 in. x 1/4 in.	235
1 in. x 0 (28M)	235
1/2 in. x 0 (28M)	210
3/8 in. x 0 (28M)	195
1/4 in. x 0 (28M)	185

Cost $43,000

Feed	tph
28M x 100M	25

k) Sieve Bends

2.5 ft. radius

Width (feet)	Price
3	$2,960
4	$3,500
5	$4,000
6	$4,600
7	$5,525
8	$6,500

5 ft. radius

Width (feet)	Price
3	$3,925
4	$5,350
5	$6,150
6	$6,875
7	$8,100
8	$9,175

Price includes distribution box.

Sizing based on sieves handling up to 11 tph of dry coal per foot sieve width.

l) Dense Medium Recovery System

Cost estimate is based on $31,000 for 100 tph of heavy media capacity. Cost versus capacity estimate is:

$$\text{Cost} = \$31{,}000 \left(\frac{\text{tph heavy media capacity}}{100}\right)^{0.75}$$

Heavy Media Capacity (tph)	Cost
50	$ 18,500
100	$ 31,000
200	$ 52,000
300	$ 71,000
400	$ 88,000
500	$103,000

m) Vacuum Disc Filter

Basis: For coal slurry, 40-60 pounds material/hr/ft^2 of filtering area

Disc Diameter (ft)	Filtering Area/Disc (ft^2)
10.5	155
11	160
12.5	228
13	244

Filter for Coal Slurry (prices include pumps and motors)

Size (diameter)	Capacity (tph)	Price
10.5 ft, 7 discs	27	$130,000
10.5 ft, 10 discs	39	$170,000
12.5 ft, 10 discs	57	$216,000
12.5 ft, 14 discs	80	$280,000

Filter For Refuse (prices include pumps and motors)

Size (diameter)	Capacity (tph)	Price
10.5 ft, 7 discs	11	\$113,000
10.5 ft, 10 discs	15.5	\$154,000
12.5 ft, 10 discs	23	\$193,000
12.5 ft, 14 discs	32	\$250,000

n) Static Thickener

Estimates for units 90 to 200 feet in diameter

Shallow Thickener

Basis: 0.5 gal/min/ft^2 with input solids concentration 3.4%

$D = 17.5\ (\text{tph solids})^{1/2}$

Installed Cost = \$2,000/ft. dia. plus \$20,000 for slurry tank

$= \$35{,}000\ (\text{tph})^{1/2} + \$20{,}000$

Deep Thickener

Basis: 1 gal/min/ft^2 with solids concentration 3.4%

$D = 12.32\ (\text{tph solids})^{1/2}$

Installed Cost = $\$30{,}825\ (\text{tph})^{1/2} + \$20{,}000$

o) Slurry Feed Pumps

Capacity x Head Factor =

$$\frac{\text{cap. in gpm} \times \text{head differential in ft} \times \text{spec. grav. of slurry}}{2.31}$$

Base cost of pump and driver is defined in terms of capacity x head factor.

Actual cost equals base cost x material factor.

Material factor is 1.0 for cast iron and 1.95 for stainless steel.

Base Cost Values

Capacity x Head Factor	Cost
500	$1,000
1,000	$1,100
5,000	$1,300
10,000	$1,900
50,000	$3,300
100,000	$5,200
200,000	$9,000

p) Tanks (e.g. sump tanks)

Cost = \$1,000 (1.2 + 1.8 x capacity in 1,000 gallons)

APPENDIX D

OPERATION AND MAINTENANCE COSTS AND INFORMATION FOR TEN REPRESENTATIVE COAL CLEANING PLANTS

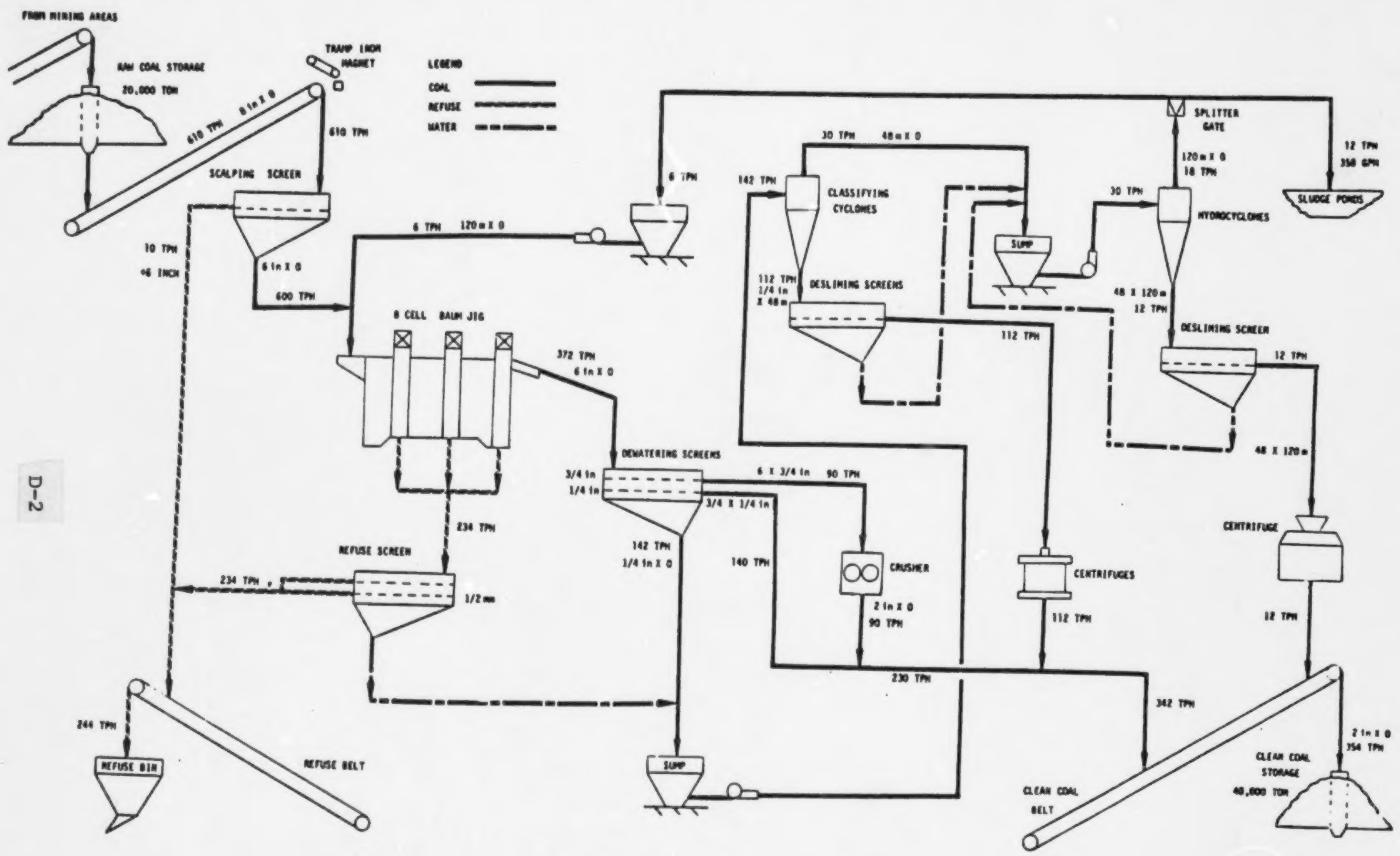
FROM MINING AREAS
RAW COAL STORAGE
20,000 TON
610 TPH 6 in X 0
TRAMP IRON MAGNET
610 TPH
LEGEND
COAL
REFUSE
WATER
SCALPING SCREEN
10 TPH
+6 INCH
6 in X 0
600 TPH
6 TPH 120 m X 0
6 TPH
8 CELL BAUM JIG
372 TPH
6 in X 0
DEWATERING SCREENS
3/4 in
1/4 in
6 X 3/4 in 90 TPH
3/4 X 1/4 in
142 TPH
1/4 in X 0
140 TPH
CRUSHER
2 in X 0
90 TPH
234 TPH
REFUSE SCREEN
234 TPH
1/2 mm
244 TPH
REFUSE BIN
REFUSE BELT
SUMP
230 TPH
30 TPH 48 m X 0
142 TPH
CLASSIFYING CYCLONES
112 TPH
1/4 in
X 48 m
DESLIMING SCREENS
112 TPH
SUMP
CENTRIFUGES
112 TPH
30 TPH
SPLITTER GATE
120 m X 0
18 TPH
HYDROCYCLONES
48 X 120 m
12 TPH
DESLIMING SCREEN
12 TPH
48 X 120 m
CENTRIFUGE
12 TPH
12 TPH
350 GPM
SLUDGE PONDS
342 TPH
CLEAN COAL BELT
2 in X 0
354 TPH
CLEAN COAL STORAGE
40,000 TON

FIGURE D-1. EXAMPLE 1 - JIG PROCESS(SIMPLE)- PREPARATION PLANT FLOW SHEET

TABLE D-1. EXAMPLE 1 - JIG PROCESS (SIMPLE)- PREPARATION PLANT OPERATING & MAINTENANCE PERSONNEL

General Non-Union Management		Quantity
Preparation Manager (1/4 time)		1

Operating Shift (2 per day)

Title	Union Classification	Quantity
Foreman	NU*	1
Plant Operator	4-E	1
Electrician/Mechanic	4-A	1
Repairman Helper (Greaser)	2-F	1
Utility Man	1-H	2
Mobile Equipment Operator (Raw and Clean Coal Handling)		
Dozer Operator	3-A	2
	Total	8

Maintenance Shift (1 per day)

Foreman	NU*	1
Mechanic	4-C	3
Utility Man	1-H	1
	Total	5

Personnel Summary

General Management		1
Operating Shifts		16
Maintenance Shift		5
	Total	22

*NU-Non-Union

TABLE D-2. EXAMPLE 1 - JIG PROCESS(SIMPLE)- OPERATING & MAINTENANCE COSTS
(Fourth Quarter 1976 Values)

COST CATEGORY	Per Ton Raw Coal	Per Ton Clean Coal
Labor -		
Supervisory (Non-Union)	$0.044	$0.075
Operating & Maintenance (Union)	0.303	0.514
Overhead -		
Fringe Benefits - 25% Non-Union	0.011	0.019
- 21% Union	0.064	0.108
Other - Includes Welfare Fund, Payroll Taxes, Property Taxes, Insurance, etc.	0.059	0.100
Supplies -		
Operating	0.155	0.262
Maintenance	0.148	0.251
Major Maintenance - Scheduled repairs and plant improvements	0.134	0.228
Electricity -	0.073	0.123
Subcontract Services to Dip Sludge Ponds, Haul Refuse & Miscellaneous Expenses	0.599	1.016
O & M Cost - Not Including Capital Amortization	$1.59	$2.70
Capital Amortization - 10 Yrs. - 30% Utilization	0.38	0.65
Total Operating & Maintenance Cost	$1.97	$3.35
Cost Per Million Btu (12,111 Btu/lb)		$0.138

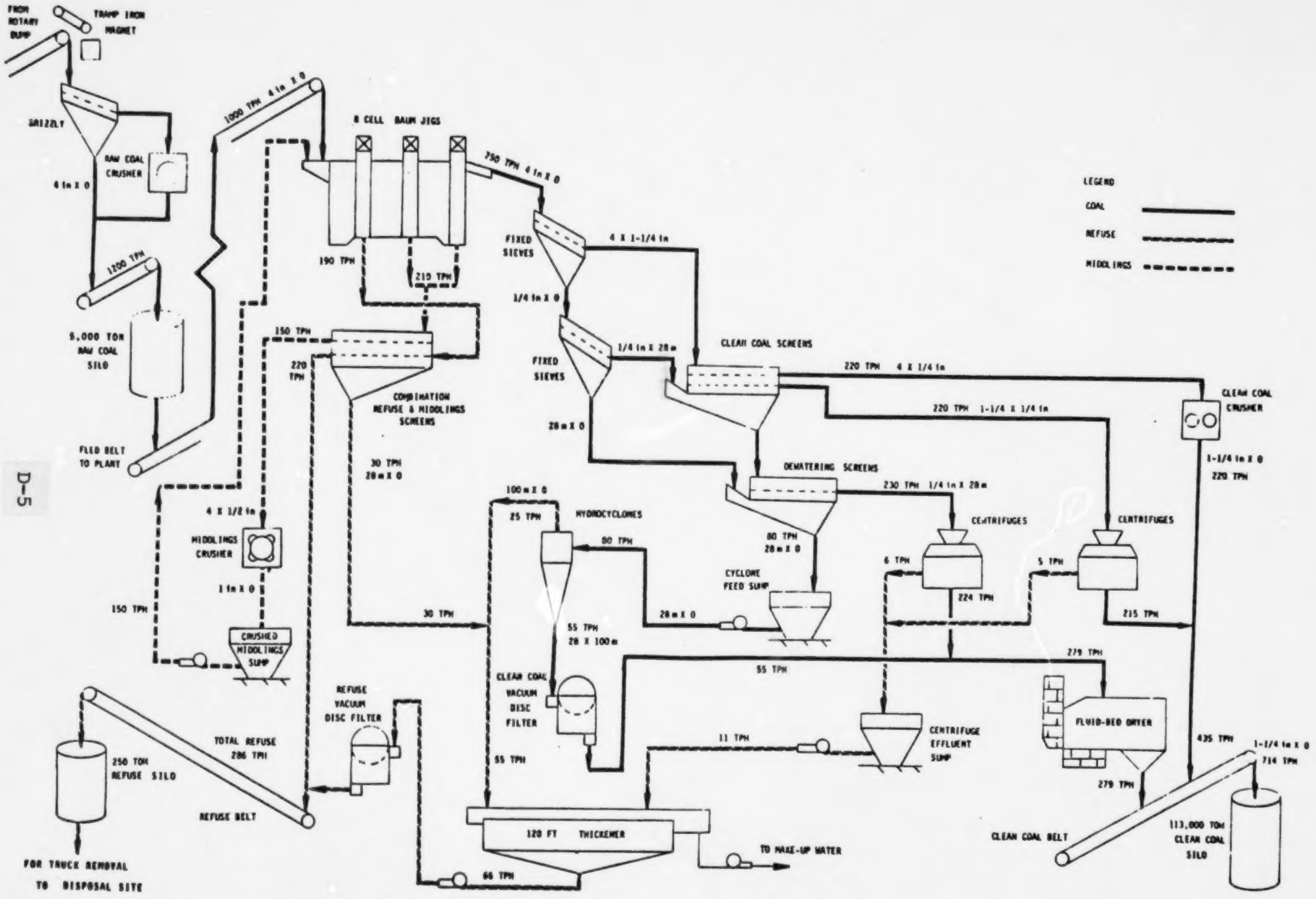
FROM ROTARY DUMP
TRAMP IRON MAGNET
GRIZZLY
RAW COAL CRUSHER
4 in X 0
1200 TPH
5,000 TON RAW COAL SILO
FEED BELT TO PLANT
1000 TPH 4 in X 0
8 CELL BAUM JIGS
750 TPH 4 in X 0
190 TPH
210 TPH
150 TPH
220 TPH
COMBINATION REFUSE & MIDDLINGS SCREENS
30 TPH 28 m X 0
4 X 1/2 in
MIDDLINGS CRUSHER
1 in X 0
150 TPH
CRUSHED MIDDLINGS SUMP
FIXED SIEVES
4 X 1-1/4 in
1/4 in X 0
FIXED SIEVES
1/4 in X 28 m
28 m X 0
CLEAN COAL SCREENS
220 TPH 4 X 1/4 in
220 TPH 1-1/4 X 1/4 in
CLEAN COAL CRUSHER
1-1/4 in X 0
220 TPH
DEWATERING SCREENS
230 TPH 1/4 in X 28 m
80 TPH 28 m X 0
CYCLONE FEED SUMP
28 m X 0
100 m X 0
25 TPH
HYDROCYCLONES
80 TPH
55 TPH 28 X 100 m
CLEAN COAL VACUUM DISC FILTER
30 TPH
55 TPH
CENTRIFUGES
6 TPH
224 TPH
CENTRIFUGES
5 TPH
215 TPH
279 TPH
55 TPH
CENTRIFUGE EFFLUENT SUMP
11 TPH
FLUID-BED DRYER
279 TPH
435 TPH
1-1/4 in X 0
714 TPH
113,000 TON CLEAN COAL SILO
CLEAN COAL BELT
120 FT THICKENER
TO MAKE-UP WATER
66 TPH
REFUSE VACUUM DISC FILTER
TOTAL REFUSE 286 TPH
REFUSE BELT
250 TON REFUSE SILO
FOR TRUCK REMOVAL TO DISPOSAL SITE
LEGEND
COAL
REFUSE
MIDDLINGS

FIGURE D-2. EXAMPLE 2 - JIG PROCESS(INTERMEDIATE)- PREPARATION PLANT FLOW SHEET

TABLE D-3. EXAMPLE 2 - JIG PROCESS (INTERMEDIATE)- PREPARATION PLANT OPERATING & MAINTENANCE PERSONNEL

General Non-Union Management	Quantity
Preparation Manager	1
General Foreman	1

Operating Shift (1st)

Title	Union Classification	Quantity
Foreman	NU*	1
Plant Operator - Central	4-E	1
Stationary Equipment Operator (Thermal Dryer).	3-C	1
Electrician	4-A	2
Mechanic	4-C	1
Mobile Equipment Operator		
Truck Driver (Refuse)	3-A	2
Dozer Operator	3-A	1
Repairman Helper (Greaser)	2-F	2
Utility Man	1-H	2
Car Dumper	1-B**	1
	Total	14

Operating Shift (2nd)

Title	Union Classification	Quantity
Foreman	NU*	1
Plant Operator - Central	4-E	1
Stationary Equipment Operator (Thermal Dryer)	3-C	1
Mechanic	4-C	1
Mobile Equipment Operator		
Truck Driver (Refuse)	3-A	2
Dozer Operator	3-A	1
Utility Man	1-H	2
Car Dumper	1-B**	1
	Total	10

TABLE D-3. (continued)

Maintenance Shift	Union Classification	Quantity
Foreman	NU*	1
Mechanic	4-C	11
Car Dumper	1-B**	1
	Total	13

Personnel Summary		
General Management		2
Operating Shifts		24
Maintenance Shift		13
	Total	39

---

* NU-Non-Union

**Car Dumper Operator is paid at Job Class 3 Rate of Pay when equipment is being operated to dump the car.

TABLE D-4. EXAMPLE 2 - JIG PROCESS(INTERMEDIATE)- OPERATING & MAINTENANCE COSTS (Fourth Quarter 1976 Values)

COST CATEGORY	Per Ton Raw Coal	Per Ton Clean Coal
Labor -		
Supervisory (Non-Union)	$0.039	$0.054
Operating & Maintenance (Union)	0.464	0.650
Overhead -		
Includes Training Wages, Welfare Fund, Payroll Taxes, Workmen's Compensation, etc.	0.211	0.296
Supplies -		
Operating - Water Conditioners, Flocculants, Electric Repairs & Parts, etc.	0.141	0.198
Maintenance - Replacement Parts, etc.	0.183	0.256
Fuel and Power -	0.233	0.326
Refuse Expense -		
In house and purchased services associated with refuse disposal such as truck parts, maintenance, etc.	0.132	0.185
Thermal Dryer Fuel - Based Upon 4.7 Tons/Hr. Coal Consumption & Cost of Coal $20/Ton.	0.094	0.132
Miscellaneous Expense - Repair & Maintenance Items Not Normally Inventoried or Requiring Outside Subcontract Svcs.	0.321	0.449
O & M Cost - Not Including Capital Amortization	$1.82	$2.55
Capital Amortization 10 Yrs. - 30% Utilization	0.80	1.12
Total Operating & Maintenance Cost	$2.62	$3.67
Cost Per Million Btu (12,079 Btu/lb)		$0.152

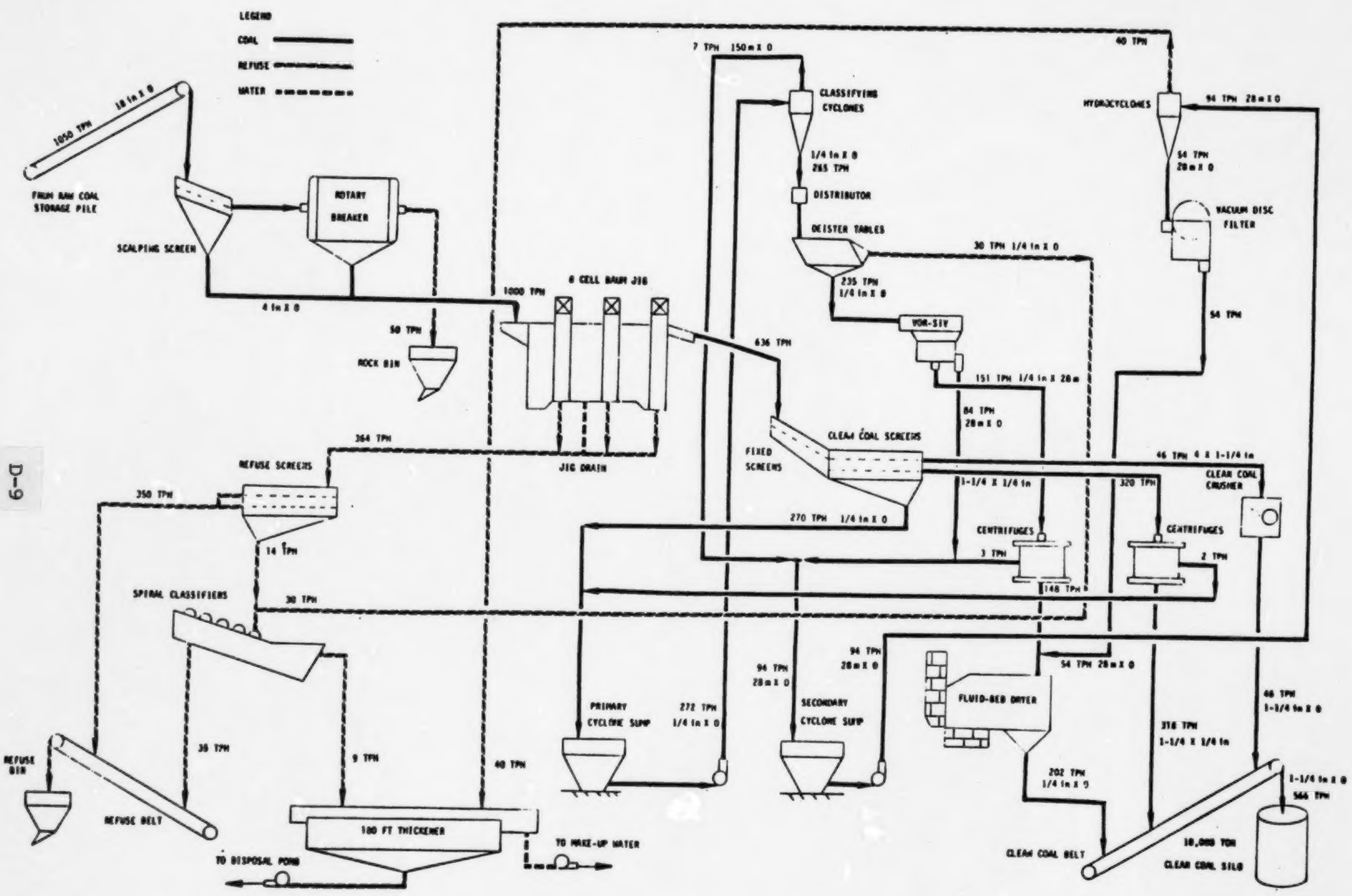
LEGEND
COAL
REFUSE
WATER
1050 TPH
18 in X 0
FROM RAW COAL STORAGE PILE
SCALPING SCREEN
ROTARY BREAKER
4 in X 0
50 TPH
ROCK BIN
1000 TPH
8 CELL BAUM JIG
JIG DRAIN
364 TPH
REFUSE SCREENS
350 TPH
14 TPH
SPIRAL CLASSIFIERS
30 TPH
35 TPH
9 TPH
40 TPH
REFUSE BIN
REFUSE BELT
100 FT THICKENER
TO DISPOSAL POND
TO MAKE-UP WATER
7 TPH 150 m X 0
CLASSIFYING CYCLONES
1/4 in X 0
265 TPH
DISTRIBUTOR
DEISTER TABLES
30 TPH 1/4 in X 0
235 TPH
1/4 in X 0
VOR-SIV
636 TPH
151 TPH 1/4 in X 28 m
84 TPH
28 m X 0
FIXED SCREENS
CLEAN COAL SCREENS
1-1/4 X 1/4 in
270 TPH 1/4 in X 0
CENTRIFUGES
3 TPH
148 TPH
320 TPH
CENTRIFUGES
2 TPH
46 TPH 4 X 1-1/4 in
CLEAN COAL CRUSHER
PRIMARY CYCLONE SUMP
272 TPH
1/4 in X 0
94 TPH
28 m X 0
SECONDARY CYCLONE SUMP
94 TPH
28 m X 0
40 TPH
HYDROCYCLONES
94 TPH 28 m X 0
54 TPH
28 m X 0
VACUUM DISC FILTER
54 TPH
54 TPH 28 m X 0
FLUID-BED DRYER
202 TPH
1/4 in X 0
318 TPH
1-1/4 X 1/4 in
46 TPH
1-1/4 in X 0
1-1/4 in X 0
566 TPH
CLEAN COAL BELT
10,000 TON
CLEAN COAL SILO

FIGURE D-3. EXAMPLE 3 - JIG PROCESS(INTERMEDIATE)- PREPARATION PLANT FLOW SHEET

TABLE D-5. EXAMPLE 3 - JIG PROCESS(INTERMEDIATE)- PREPARATION PLANT OPERATING & MAINTENANCE PERSONNEL

General Non-Union Management		Quantity
Preparation Manager (1/4 time) -		1
General Foreman -		1

Operating Shift (Two per day) Title	Union Classification	Quantity
Foreman	NU*	1
Plant Operator	4-E	1
Electrician	4-A	1
Mechanic	4-C	2
Mobile Equipment Operator (Dozer, Front End Loader, and Refuse Truck Driver)	3-A	4
Welder	4-D	1
Stationary Equipment Operator (Thermal Dryer Operator)	3-C	1
Repairman Helper (Greaser)	2-F	1
Utility Man	1-H	2
	Total	14

Maintenance Shift		
Foreman	NU*	1
Electrician	4-A	1
Mechanic	4-C	3
Mobile Equipment Operator	3-A	1
Utility Man	1-H	2
	Total	8

Personnel Summary		
General Management		2
Operating Shifts		28
Maintenance Shift		8
	Total	38

*NU-Non-Union

TABLE D-6. EXAMPLE 3 - JIG PROCESS (INTERMEDIATE)- OPERATING & MAINTENANCE COSTS (Fourth Quarter 1976 Values)

COST CATEGORY	Per Ton Raw Coal	Per Ton Clean Coal
Labor -		
Supervisory (Non-Union)	$0.054	$0.095
Operating & Maintenance (Union)	0.428	0.757
Includes miscellaneous salaries for watchmen, etc.		
Overhead -		
Fringe Benefits - 26% Non-Union	0.014	0.025
- 22% Union	0.094	0.167
Other - Includes Welfare Fund, training costs, etc. (15% of total labor)	0.072	0.128
Supplies -		
Includes water conditioners, replacement parts, lab supplies, health & safety expenses, necessary equipment rental, etc.	0.538	0.950
Fuel and Power -	0.170	0.301
Thermal Dryer Fuel - Based upon 3.4 Tons/Hr Coal Consumption and Cost of Coal $20/Ton	0.068	0.120
Miscellaneous - Subcontract Services, etc.	0.076	0.127
O & M Cost - Not Including Capital Amortization	$1.51	$2.67
Capital Amortization - 10 Yrs. - 30% Utilization	0.71	1.25
Total Operating & Maintenance Cost	$2.22	$3.92
Cost Per Million Btu (12,455 Btu/lb)		$0.157

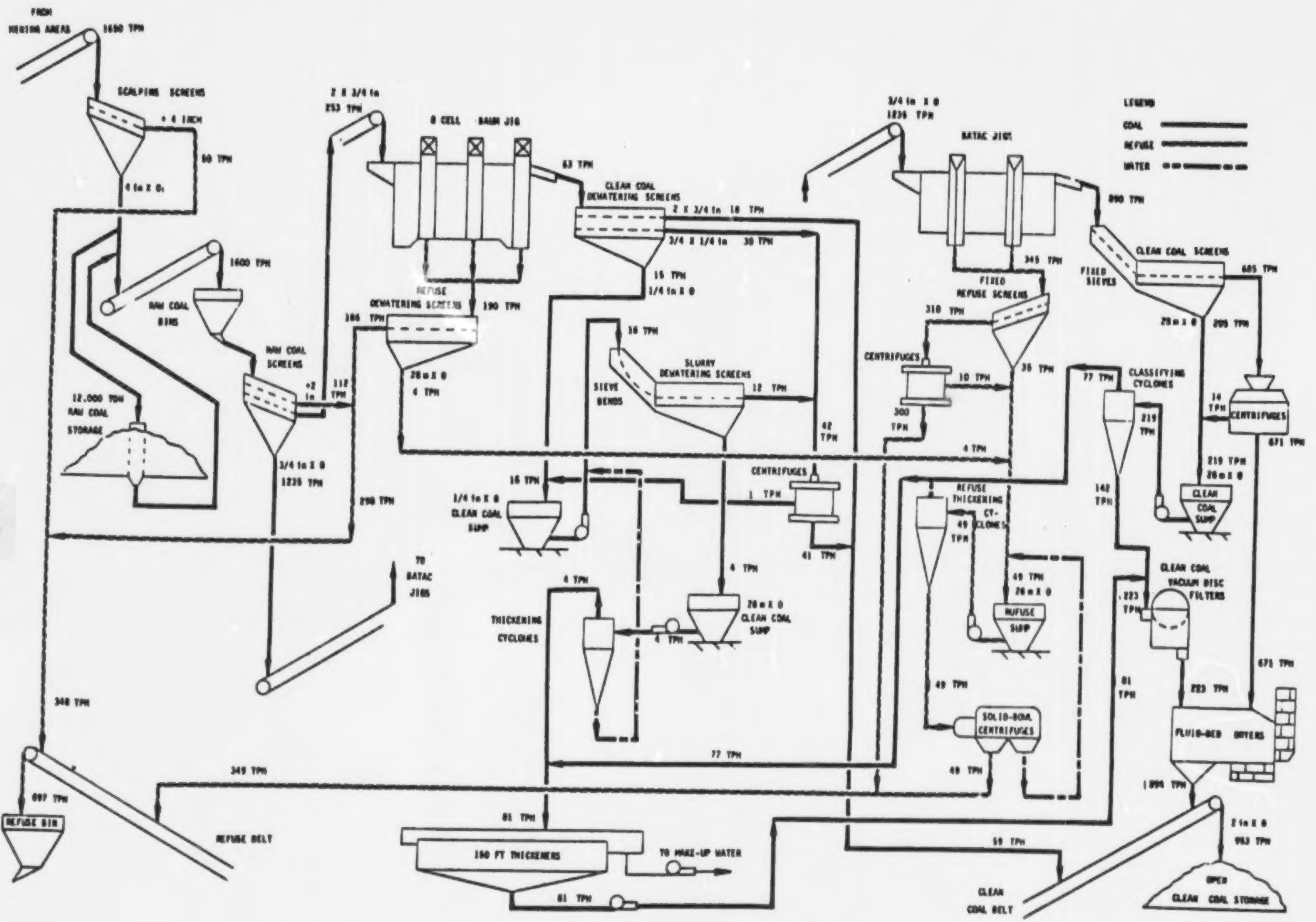
FROM
MINING AREAS
1650 TPH
SCALPING SCREENS
+ 4 INCH
50 TPH
4 in X 0
1600 TPH
RAW COAL
BINS
12,000 TON
RAW COAL
STORAGE
RAW COAL
SCREENS
+2
in
112
TPH
3/4 in X 0
1235 TPH
298 TPH
2 X 3/4 in
253 TPH
8 CELL BAUM JIG
63 TPH
REFUSE
DEWATERING SCREENS
190 TPH
186 TPH
28 m X 0
4 TPH
CLEAN COAL
DEWATERING SCREENS
2 X 3/4 in 18 TPH
3/4 X 1/4 in 30 TPH
15 TPH
1/4 in X 0
16 TPH
SIEVE
BENDS
SLURRY
DEWATERING SCREENS
12 TPH
42
TPH
16 TPH
1/4 in X 0
CLEAN COAL
SUMP
CENTRIFUGES
1 TPH
41 TPH
4 TPH
28 m X 0
CLEAN COAL
SUMP
4 TPH
THICKENING
CYCLONES
4 TPH
TO
BATAC
JIGS
348 TPH
697 TPH
REFUSE BIN
349 TPH
REFUSE BELT
77 TPH
81 TPH
160 FT THICKENERS
TO MAKE-UP WATER
81 TPH
3/4 in X 0
1236 TPH
BATAC JIGS
LEGEND
COAL
REFUSE
WATER
890 TPH
345 TPH
FIXED
REFUSE SCREENS
310 TPH
CENTRIFUGES
10 TPH
35 TPH
300
TPH
4 TPH
FIXED
SIEVES
CLEAN COAL SCREENS
685 TPH
28 m X 0
205 TPH
14
TPH
CENTRIFUGES
671 TPH
77 TPH
CLASSIFYING
CYCLONES
219
TPH
142
TPH
219 TPH
28 m X 0
CLEAN
COAL
SUMP
REFUSE
THICKENING
CY-
CLONES
49
TPH
49 TPH
28 m X 0
REFUSE
SUMP
49 TPH
SOLID-BOWL
CENTRIFUGES
49 TPH
CLEAN COAL
VACUUM DISC
FILTERS
.223
TPH
81
TPH
223 TPH
671 TPH
FLUID-BED DRYERS
1894 TPH
2 in X 0
953 TPH
OPEN
CLEAN COAL STORAGE
59 TPH
CLEAN
COAL BELT

FIGURE D-4. EXAMPLE 4 - JIG PROCESS (COMPLEX)- PREPARATION PLANT FLOW SHEET

TABLE D-7. EXAMPLE 4 - JIG PROCESS (COMPLEX)- PREPARATION PLANT OPERATING AND MAINTENANCE PERSONNEL

General Non-Union Management		Quantity
Preparation Plant Superintendent		1
Operating Shift (1st)		
Title	Union Classification	Quantity
Shift Foreman	NU*	1
Electrical Maintenance Foreman	NU*	1
Plant Operator	4-E	1
Electrician	4-A	2
Mechanic	4-C	3
Stationary Equipment Operator - (Includes two thermal dryer operators)	3-C	4
Mobile Equipment Operator	3-A	5
Dozer & Truck Drivers		
Utility Man (Screenman)	1-H	1
Laborer	1-J	2
	Total	20
Operating Shift (2nd)		
Shift Foreman	NU*	1
Plant Operator	4-E	1
Electrician	4-A	2
Mechanic	4-C	3
Stationary Equipment Operator	3-C	4
Mobile Equipment Operator	3-A	4
Railroad Car Loader Operator	3-E	1
Utility Man (Screenman)	1-H	1
Laborer	1-J	2
	Total	19

TABLE D-7. (continued)

Maintenance Shift		
Shift Foreman	NU*	2
Electrician	4-A	2
Mechanic	4-C	6
Electrician Helper	2-C	3
Mechanic Helper	2-E	3
	Total	16
Personnel Summary		
General Management		1
Operating Shifts		39
Maintenance Shift		16
	Total	56

*NU-Non-Union

TABLE D-8. EXAMPLE 4 - JIG PROCESS (COMPLEX)- OPERATING AND MAINTENANCE COSTS (Fourth Quarter 1976 Values)

COST CATEGORY	Per Ton Raw Coal	Per Ton Clean Coal
Labor -		
Supervisory (Non-Union)	$0.030	$0.050
Operating & Maintenance (Union)	0.387	0.650
Overhead -		
Includes Payroll Taxes, Insurance, Welfare Fund, Vacations, Holidays, etc. for all Preparation Plant Employees	0.250	0.420
Supplies		
Operating	0.137	0.230
Maintenance - Repair Parts and Materials Associated with Routine Maintenance	0.273	0.458
Thermal Dryer Fuel - Based upon 17 Tons/Hr Coal Consumption and Cost of Coal $20/Ton	0.213	0.357
Electricity	0.387	0.650
Other Expenses	0.084	0.141
O & M Cost - Not Including Capital Amortization	$1.76	$2.96
Capital Amortization - 10 Yrs. - 30% Utilization	0.84	1.40
Total Operating & Maintenance Cost	$2.60	$4.36
Cost Per Million Btu (13,418 Btu/lb)		$0.162

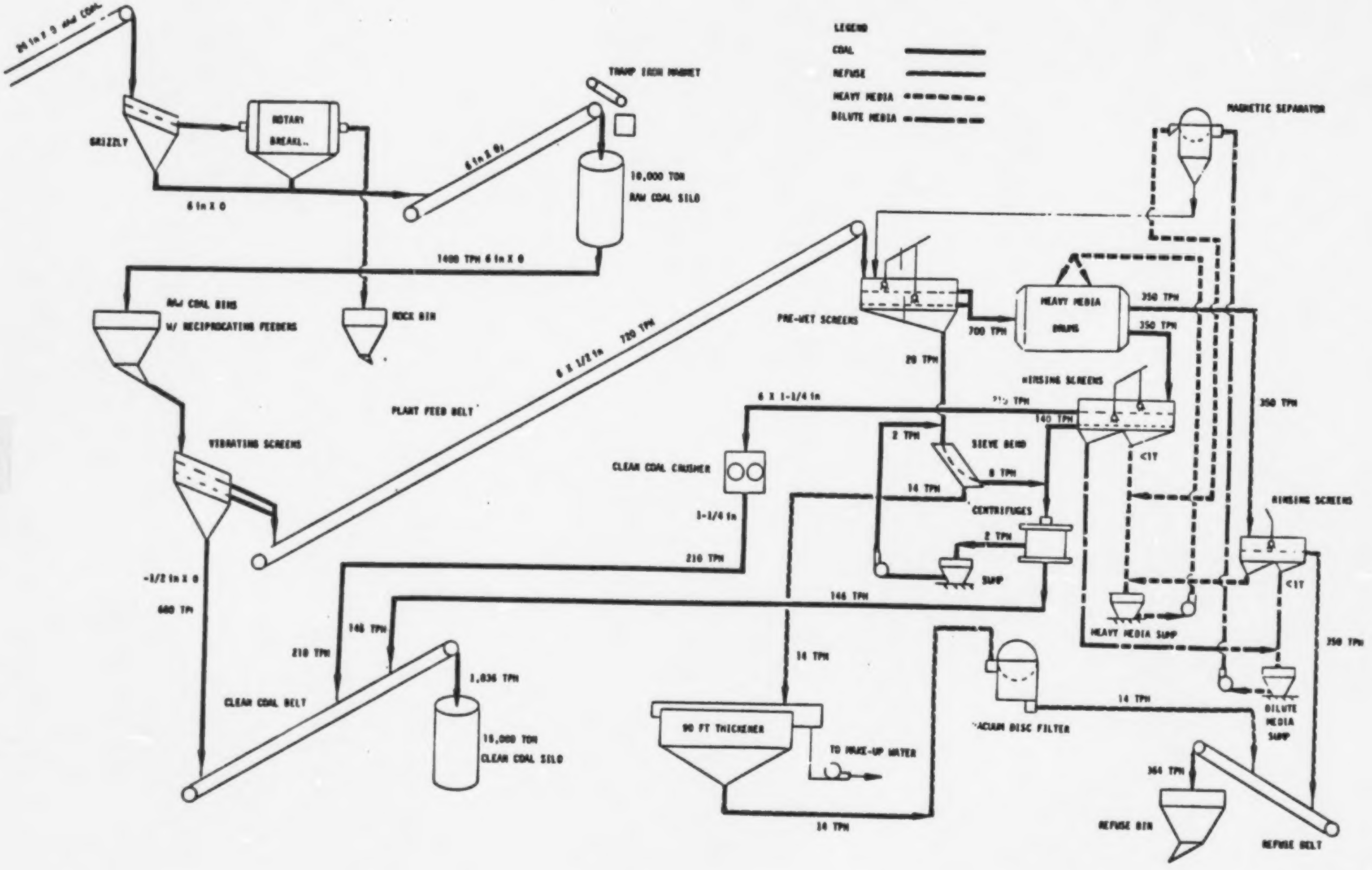
24 in X 0 RAW COAL
GRIZZLY
ROTARY BREAKER
6 in X 0
6 in X 0
TRAMP IRON MAGNET
10,000 TON RAW COAL SILO
1400 TPH 6 in X 0
RAW COAL BINS W/ RECIPROCATING FEEDERS
ROCK BIN
6 X 1/2 in 720 TPH
PLANT FEED BELT
VIBRATING SCREENS
-1/2 in X 0 680 TPH
LEGEND
COAL
REFUSE
HEAVY MEDIA
DILUTE MEDIA
MAGNETIC SEPARATOR
PRE-WET SCREENS
700 TPH
HEAVY MEDIA DRUMS
350 TPH
350 TPH
20 TPH
RINSING SCREENS
6 X 1-1/4 in
210 TPH
140 TPH
350 TPH
CLEAN COAL CRUSHER
1-1/4 in
210 TPH
2 TPH
SIEVE BEND
8 TPH
14 TPH
CENTRIFUGES
2 TPH
SUMP
<1T
RINSING SCREENS
<1T
146 TPH
HEAVY MEDIA SUMP
350 TPH
210 TPH
146 TPH
1,036 TPH
CLEAN COAL BELT
15,000 TON CLEAN COAL SILO
14 TPH
90 FT THICKENER
TO MAKE-UP WATER
14 TPH
VACUUM DISC FILTER
14 TPH
DILUTE MEDIA SUMP
364 TPH
REFUSE BIN
REFUSE BELT

FIGURE D-5. EXAMPLE 5 - HEAVY MEDIUM PROCESS(COMPLEX)-PREPARATION PLANT FLOW SHEET

TABLE D-9. EXAMPLE 5 - HEAVY MEDIUM PROCESS (COMPLEX)-PREPARATION PLANT OPERATING AND MAINTENANCE PERSONNEL

General Non-Union Management		Quantity
Preparation Superintendent	-	1
General Foreman	-	1

Operating Shift (Two per day)

Title	Union Classification	Quantity
Foreman	NU*	1
Plant Operator	4-E	1
Stationary Equipment Operator - (Vacuum filter, thickener, media system)	3-C	1
Electrician	4-A	1.
Screenman (cleaner)	1-H	2
Utility Man	1-H	1
Repairman (Belt Mechanic)	3-B	1
Mobile Equipment Operator (Refuse Handling)		
Truck Driver	3-A	3
Dozer Operator	3-A	2
	Total	13

Maintenance Shift (One per day)

Foreman	NU*	1
Mechanic	4-C	7
Repairman	3-B	1
Utility Man	1-H	1
Mobile Equipment Operator		
Dozer Operator	3-A	2
	Total	12

Personnel Summary

General Management		2
Operating Shifts		26
Maintenance Shift		12
	Total	40

*NU-Non-Union

TABLE D-10. EXAMPLE 5 - HEAVY MEDIUM PROCESS (COMPLEX)-OPERATING AND MAINTENANCE COSTS (Fourth Quarter 1976 Values)

COST CATEGORY	Per Ton Raw Coal	Per Ton Clean Coal
Labor -		
Supervisory (Non Union)	$0.148	$0.200
Operating (Union)	0.360	0.487
Maintenance (Union)	0.254	0.343
Overhead -		
Non-Union Benefits - Includes Payroll Taxes, Group Life & Medical Insurance, Pension Fund, etc.	0.030	0.040
Union Benefits - Includes Payroll Taxes, Welfare Fund, Vacations, Holidays, Clothing Allowance, etc.	0.184	0.249
Other	0.112	0.152
Supplies		
Operating - Magnetite, Flocculants, and clay settler accounts for 22%.*	0.610	0.824
Maintenance - Equipment Repair, etc.	0.504	0.681
Electricity	0.165	0.223
O & M Cost-		
Not Including Capital Amortization	$2.37	$3.20
Capital Amortization 10 years - 30% Utilization	0.42	0.56
Total Operating & Maintenance Cost	$2.79	$3.76
Cost Per Million Btu (10,168 Btu/lb)		$0.185

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*Consumption of these major additives on each ton of clean coal is: Magnetite 1 to 1.5 lb; Flocculant 0.015 lb; and clay settler 0.15 lb. When the coal is damp and muddy, consumption is much higher. On an annual basis, their cost averages $0.18 to $0.20 per ton of product.

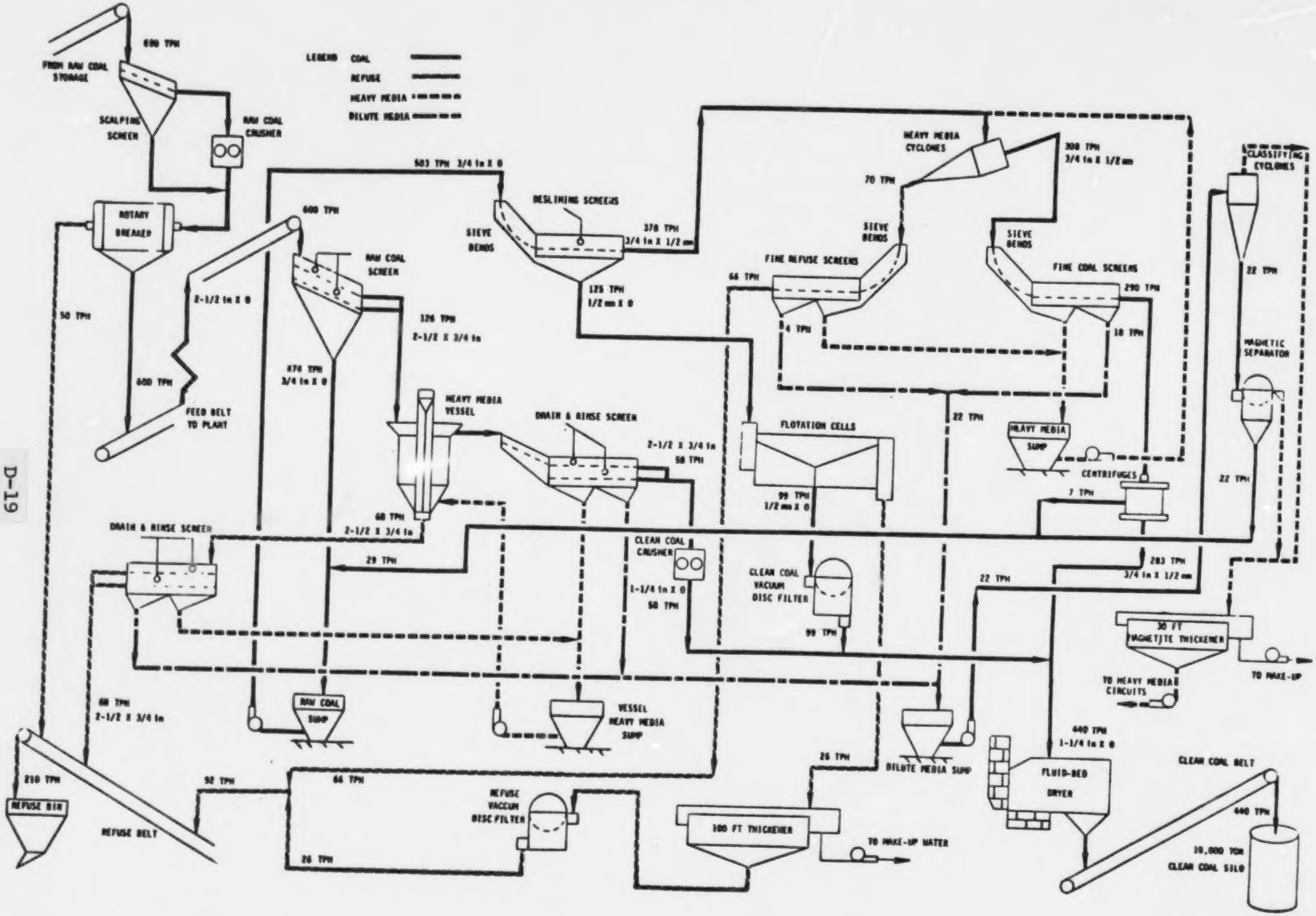
600 TPH
FROM RAW COAL STORAGE
SCALPING SCREEN
RAW COAL CRUSHER
LEGEND COAL
REFUSE
HEAVY MEDIA
DILUTE MEDIA
ROTARY BREAKER
50 TPH
600 TPH
2-1/2 in X 0
FEED BELT TO PLANT
503 TPH 3/4 in X 0
600 TPH
RAW COAL SCREEN
126 TPH
2-1/2 X 3/4 in
474 TPH
3/4 in X 0
SIEVE BENDS
DESLIMING SCREENS
378 TPH
3/4 in X 1/2 mm
125 TPH
1/2 mm X 0
HEAVY MEDIA VESSEL
DRAIN & RINSE SCREEN
2-1/2 X 3/4 in
58 TPH
60 TPH
2-1/2 X 3/4 in
29 TPH
DRAIN & RINSE SCREEN
CLEAN COAL CRUSHER
1-1/4 in X 0
58 TPH
HEAVY MEDIA CYCLONES
70 TPH
308 TPH
3/4 in X 1/2 mm
SIEVE BENDS
SIEVE BENDS
FINE REFUSE SCREENS
FINE COAL SCREENS
66 TPH
4 TPH
290 TPH
18 TPH
22 TPH
FLOTATION CELLS
99 TPH
1/2 mm X 0
HEAVY MEDIA SUMP
CENTRIFUGES
7 TPH
CLASSIFYING CYCLONES
22 TPH
MAGNETIC SEPARATOR
22 TPH
CLEAN COAL VACUUM DISC FILTER
99 TPH
22 TPH
283 TPH
3/4 in X 1/2 mm
30 FT MAGNETITE THICKENER
TO MAKE-UP
TO HEAVY MEDIA CIRCUITS
60 TPH
2-1/2 X 3/4 in
RAW COAL SUMP
VESSEL HEAVY MEDIA SUMP
DILUTE MEDIA SUMP
210 TPH
REFUSE BIN
REFUSE BELT
92 TPH
66 TPH
26 TPH
REFUSE VACCUM DISC FILTER
26 TPH
100 FT THICKENER
TO MAKE-UP WATER
440 TPH
1-1/4 in X 0
FLUID-BED DRYER
CLEAN COAL BELT
440 TPH
10,000 TON CLEAN COAL SILO

FIGURE D-6. EXAMPLE 6 - HEAVY MEDIUM PROCESS(COMPLEX)- PREPARATION PLANT FLOW SHEET

TABLE D-11. EXAMPLE 6 - HEAVY MEDIUM PROCESS(COMPLEX)- PREPARATION PLANT OPERATING AND MAINTENANCE PERSONNEL

General Non-Union Management		Quantity
Preparation Superintendent (1/2 time)		1
General Foreman		1
	Total	2

Operating Shift (2 per day)

Title	Union Classification	Quantity
Foreman	NU*	1
Plant Operator	4-E	1
Electrician	4-A	1
Mechanic	4-C	2
Mobile Equipment Operator (Refuse Hauling & Compacting)	3-A	2
Repairman·Helper (Greaser)	2-F	1
Stationary Equipment Operator (Thermal Dryer, Media, etc.)	3-C	2
Utility Man	1-H	2
	Total	12

Maintenance Shift (1 per day)

Foreman	NU*	1
Electrician	4-A	1
Mechanic	4-C	3
Repairman	3-B	2
Repairman Helper	2-F	2
	Total	9

TABLE D-11. (continued)

Personnel Summary		
General Management		2
Operating Shifts		24
Maintenance Shift		9
	Total	35

*NU-Non-Union

TABLE D-12. EXAMPLE 6 - HEAVY MEDIUM PROCESS(COMPLEX)- OPERATING AND MAINTENANCE COSTS (Fourth Quarter 1976 Values)

COST CATEGORY	Per Ton Raw Coal	Per Ton Clean Coal
Labor -		
Supervisory (Non Union)	$0.099	$0.135
Operating & Maintenance (Union)	0.638	0.870
Overhead -		
Fringe Benefits - 25% Non-Union	0.025	0.034
- 20% Union	0.128	0.174
Other - Includes Workmens' Compensation Insurance, Payroll Taxes, Welfare Fund, etc.	0.213	0.291
Supplies -		
Operating	0.169	0.23
Maintenance & Other	0.242	0.33
Thermal Dryer Fuel -		
Based Upon 7.0 Tons/Hr Coal Consumption & Cost of Coal $20/Ton	0.233	0.318
Cleaning Plant Repair Parts	0.147	0.20
Electricity (Large Thermal Dryer)	0.334	0.456
O & M Cost -		
Not Including Capital Amortization	$2.23	$3.04
Capital Amortization - 10 years - 30% Utilization	1.31	1.79
Total Operating & Maintenance Cost	$3.54	$4.83
Cost Per Million Btu (13,619 Btu/lb)		$0.177

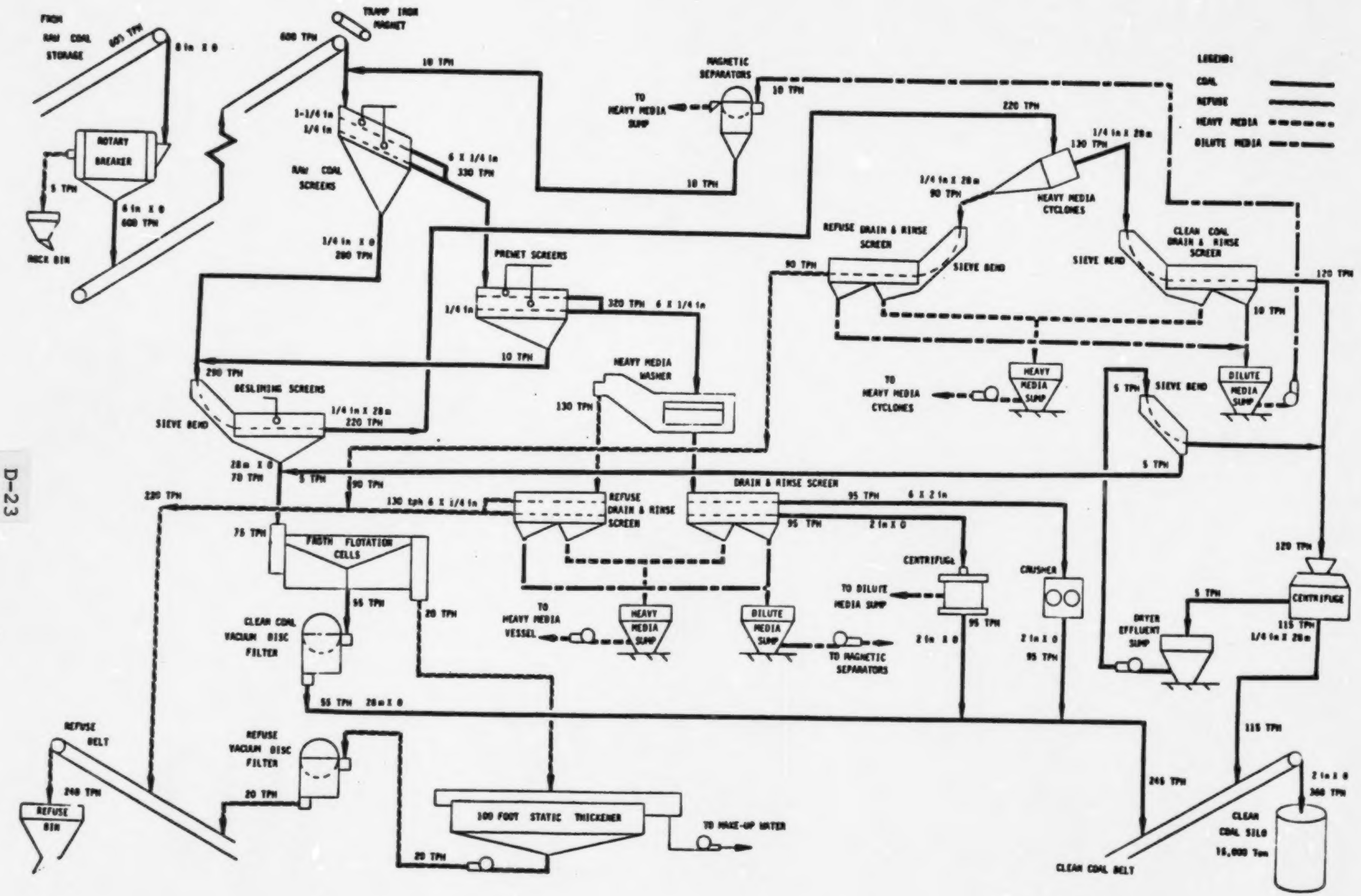
FROM RAW COAL STORAGE
601 TPH
8 in X 0
ROTARY BREAKER
5 TPH
ROCK BIN
6 in X 0
600 TPH
600 TPH
TRAMP IRON MAGNET
10 TPH
1-1/4 in
1/4 in
RAW COAL SCREENS
6 X 1/4 in
330 TPH
1/4 in X 0
290 TPH
MAGNETIC SEPARATORS
TO HEAVY MEDIA SUMP
10 TPH
10 TPH
220 TPH
PREWET SCREENS
1/4 in
320 TPH 6 X 1/4 in
10 TPH
290 TPH
DESLIMING SCREENS
SIEVE BEND
1/4 in X 28 m
220 TPH
28 m X 0
70 TPH
5 TPH
90 TPH
220 TPH
130 tph 6 X 1/4 in
HEAVY MEDIA WASHER
130 TPH
REFUSE DRAIN & RINSE SCREEN
DRAIN & RINSE SCREEN
95 TPH
6 X 2 in
95 TPH
2 in X 0
LEGEND:
COAL
REFUSE
HEAVY MEDIA
DILUTE MEDIA
220 TPH
1/4 in X 28 m
130 TPH
1/4 in X 28 m
90 TPH
HEAVY MEDIA CYCLONES
REFUSE DRAIN & RINSE SCREEN
90 TPH
SIEVE BEND
SIEVE BEND
CLEAN COAL DRAIN & RINSE SCREEN
120 TPH
10 TPH
HEAVY MEDIA SUMP
TO HEAVY MEDIA CYCLONES
DILUTE MEDIA SUMP
5 TPH
SIEVE BEND
5 TPH
75 TPH
FROTH FLOTATION CELLS
55 TPH
20 TPH
CLEAN COAL VACUUM DISC FILTER
55 TPH 28 m X 0
TO HEAVY MEDIA VESSEL
HEAVY MEDIA SUMP
DILUTE MEDIA SUMP
TO MAGNETIC SEPARATORS
CENTRIFUGE
TO DILUTE MEDIA SUMP
95 TPH
2 in X 0
CRUSHER
2 in X 0
95 TPH
120 TPH
CENTRIFUGE
5 TPH
DRYER EFFLUENT SUMP
115 TPH
1/4 in X 28 m
115 TPH
REFUSE BELT
240 TPH
REFUSE BIN
REFUSE VACUUM DISC FILTER
20 TPH
20 TPH
100 FOOT STATIC THICKENER
TO MAKE-UP WATER
245 TPH
CLEAN COAL BELT
2 in X 0
360 TPH
CLEAN COAL SILO
16,000 Ton

FIGURE D-7. EXAMPLE 7 - HEAVY MEDIUM PROCESS (COMPLEX)- PREPARATION PLANT FLOW SHEET

TABLE D-13. EXAMPLE 7 - HEAVY MEDIUM PROCESS(COMPLEX)- PREPARATION PLANT OPERATING AND MAINTENANCE PERSONNEL

General Non-Union Management	Quantity
Preparation Manager	1

Operating Shift (Two per day)

Title	Union Classification	Quantity
Foreman	NU*	1
Plant Operator	4-E	1
Electrician/Mechanic	4-A	1
Mobile Equipment Operator (Refuse Spreading & Compacting and Pushing Raw Coal Into Feeders)	3-A	2
Repairman Helper	2-F	1
General Outside Laborer	1-J	1
	Total	7

Maintenance Shift		
Foreman	NU*	1
Electrician/Mechanic	4-A	1
Repairman	3-B	3
Repairman Helper	2-F	1
	Total	6

Personnel Summary		
General Management		1
Operating Shifts		14
Maintenance Shift		6
	Total	21

*NU - Non-Union

TABLE D-14. EXAMPLE 7 - HEAVY MEDIUM PROCESS(COMPLEX)- OPERATING AND MAINTENANCE COSTS (Fourth Quarter 1976 Values)

COST CATEGORY	Per Ton Raw Coal	Per Ton Clean Coal
Labor -		
Supervisory (Non-Union)	$0.058	$0.096
Operating & Maintenance (Union)	0.211	0.352
Overhead -		
Fringe Benefits - 25% Non-Union	0.014	0.024
- 21% Union	0.044	0.074
Other - Includes Welfare Fund, Payroll Taxes, Property Taxes, Insurance, etc.	0.060	0.100
Supplies -		
Operating - Magnetite	0.055	0.091
- Other	0.307	0.511
Maintenance	0.092	0.154
Major Maintenance - Scheduled repairs and plant improvements	0.051	0.085
Electricity -	0.090	0.150
Subcontract Services For Major Equipment Repairs & Miscellaneous Expenses	0.289	0.482
O & M Cost - Not Including Capital Amortization	$1.27	$2.12
Capital Amortization - 10 Yrs. - 30% Utilization	0.82	1.36
Total Operating & Maintenance Cost	$2.09	$3.48
Cost Per Million Btu (12,697 Btu/lb)		$0.137

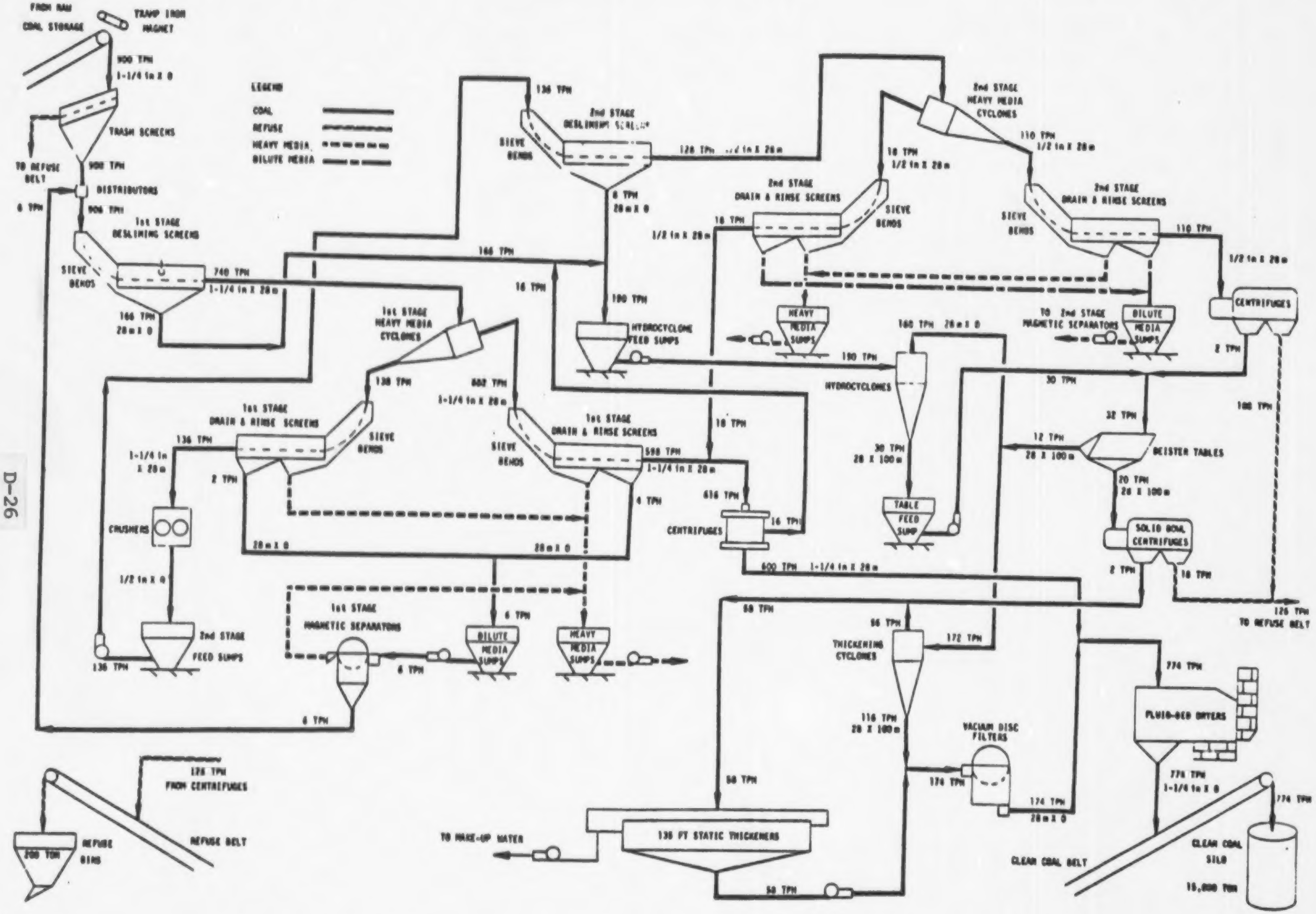
FROM RAW COAL STORAGE
TRAMP IRON MAGNET
900 TPH
1-1/4 in X 0
TRASH SCREENS
TO REFUSE BELT
900 TPH
DISTRIBUTORS
6 TPH
906 TPH
1st STAGE DESLIMING SCREENS
SIEVE BENDS
740 TPH
1-1/4 in X 28 m
166 TPH
28 m X 0
LEGEND
COAL
REFUSE
HEAVY MEDIA
DILUTE MEDIA
136 TPH
2nd STAGE DESLIMING SCREENS
SIEVE BENDS
128 TPH 1/2 in X 28 m
6 TPH
28 m X 0
166 TPH
16 TPH
190 TPH
HYDROCYCLONE FEED SUMPS
1st STAGE HEAVY MEDIA CYCLONES
138 TPH
602 TPH
1-1/4 in X 28 m
1st STAGE DRAIN & RINSE SCREENS
SIEVE BENDS
136 TPH
1-1/4 in X 28 m
2 TPH
CRUSHERS
1/2 in X 0
2nd STAGE FEED SUMPS
136 TPH
28 m X 0
28 m X 0
598 TPH
1-1/4 in X 28 m
4 TPH
616 TPH
CENTRIFUGES
16 TPH
600 TPH 1-1/4 in X 28 m
1st STAGE MAGNETIC SEPARATORS
6 TPH
DILUTE MEDIA SUMPS
HEAVY MEDIA SUMPS
6 TPH
6 TPH
2nd STAGE HEAVY MEDIA CYCLONES
18 TPH
1/2 in X 28 m
110 TPH
1/2 in X 28 m
2nd STAGE DRAIN & RINSE SCREENS
SIEVE BENDS
18 TPH
1/2 in X 28 m
2nd STAGE DRAIN & RINSE SCREENS
SIEVE BENDS
110 TPH
1/2 in X 28 m
CENTRIFUGES
HEAVY MEDIA SUMPS
TO 2nd STAGE MAGNETIC SEPARATORS
DILUTE MEDIA SUMPS
2 TPH
160 TPH 28 m X 0
190 TPH
HYDROCYCLONES
18 TPH
30 TPH
28 X 100 m
TABLE FEED SUMP
30 TPH
108 TPH
32 TPH
12 TPH
28 X 100 m
DEISTER TABLES
20 TPH
28 X 100 m
SOLID BOWL CENTRIFUGES
2 TPH
18 TPH
126 TPH
TO REFUSE BELT
58 TPH
56 TPH
THICKENING CYCLONES
172 TPH
116 TPH
28 X 100 m
VACUUM DISC FILTERS
174 TPH
174 TPH
28 m X 0
774 TPH
FLUID-BED DRYERS
774 TPH
1-1/4 in X 0
774 TPH
CLEAN COAL BELT
CLEAN COAL SILO
15,000 TON
58 TPH
135 FT STATIC THICKENERS
58 TPH
TO MAKE-UP WATER
126 TPH
FROM CENTRIFUGES
REFUSE BELT
200 TON
REFUSE BINS

FIGURE D-8. EXAMPLE 8 - HEAVY MEDIUM PROCESS (COMPLEX)- PREPARATION PLANT FLOW SHEET

TABLE D-15. EXAMPLE 8 - HEAVY MEDIUM PROCESS (COMPLEX)- PREPARATION PLANT OPERATING AND MAINTENANCE PERSONNEL

General Non-Union Management		Quantity
Preparation Manager (1/2 time)		1
General Foreman		1
	Total	2

Operating Shift - Full (2 per day)

Title	Union Classification	Quantity
Foreman	NU*	1
Plant Operator	4-E	1
Electrician	4-A	1
Mechanic	4-C	2
Mobile Equipment Operator (Refuse Hauling & Compacting)	3-A	2
Stationary Equipment Operator (Thermal Dryer & Media Operators)	3-C	2
Repairman Helper (Greaser)	2-F	1
Utility Man	1-H	3
	Total	13

Operating/Maintenance Shift - Partial (1 per day)

Title	Union Classification	Quantity
Foreman	NU*	1
Plant Operator	4-E	1
Electrician	4-A	1
Mechanic	4-C	4
Mobile Equipment Operator	3-A	2

TABLE D-15. (continued)

Stationary Equipment Operator	3-C	2
Repairman	3-B	1
Repairman Helper (Greaser)	2-F	1
Utility Man	1-H	3
	Total	16
Personnel Summary		
General Management		2
Operating Shifts - Full		26
Operating/Maintenance Shift - Partial		16
	Total	44

TABLE D-16. EXAMPLE 8 - HEAVY MEDIUM PROCESS (COMPLEX)- OPERATING AND MAINTENANCE COSTS

COST CATEGORY	Per Ton Raw Coal	Per Ton Clean Coal
Labor -		
Supervisory (Non-Union)	$0.035	$0.041
Operating & Maintenance (Union)	0.267	0.310
Overhead -		
Includes Payroll Taxes, Vacation and Holiday Pay, Welfare Fund, Taxes, Insurance, etc.	0.196	0.228
Supplies -		
Operating	0.249	0.290
Maintenance - Includes Scheduled Major Repair and Replacements	0.529	0.615
Thermal Dryer Fuel - Based upon 12.5 Tons/Hr Coal Consumption and Cost of Coal $20/Ton	0.278	0.323
Electricity	0.456	0.53
Other	0.087	0.101
O & M Cost - Not Including Capital Amortization	$2.10	$2.44
Capital Amortization - 10 Yrs. - 50% Utilization	0.81	0.94
Total Operating & Maintenance Cost	$2.91	$3.38
Cost Per Million Btu (12,473 Btu/lb)		$0.135

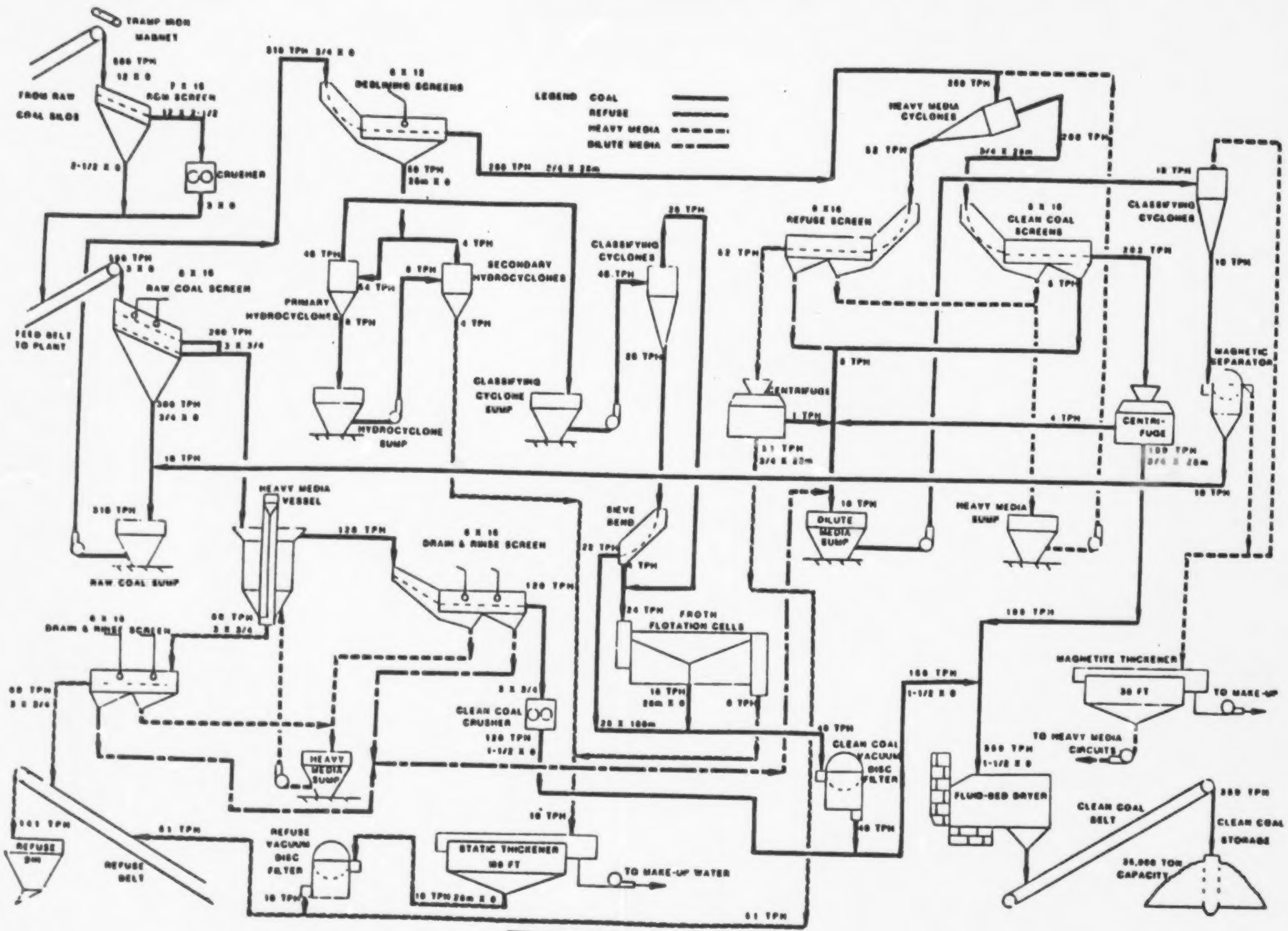
TRAMP IRON MAGNET
FROM RAW COAL SILOS
500 TPH 12 X 0
7 X 10 RGH SCREEN
12 X 2-1/2
2-1/2 X 0
CRUSHER
3 X 0
FEED BELT TO PLANT
300 TPH 3 X 0
6 X 16 RAW COAL SCREEN
200 TPH 3 X 3/4
300 TPH 3/4 X 0
310 TPH
RAW COAL SUMP
310 TPH 3/4 X 0
6 X 12 DESLIMING SCREENS
50 TPH 28m X 0
260 TPH 3/4 X 28m
LEGEND
COAL
REFUSE
HEAVY MEDIA
DILUTE MEDIA
46 TPH
PRIMARY HYDROCYCLONES
54 TPH
8 TPH
6 TPH
4 TPH
SECONDARY HYDROCYCLONES
4 TPH
HYDROCYCLONE SUMP
CLASSIFYING CYCLONE SUMP
CLASSIFYING CYCLONES
46 TPH
26 TPH
28 TPH
18 TPH
HEAVY MEDIA VESSEL
120 TPH
6 X 16 DRAIN & RINSE SCREEN
120 TPH
6 X 16 DRAIN & RINSE SCREEN
80 TPH 3 X 3/4
80 TPH 3 X 3/4
3 X 3/4
CLEAN COAL CRUSHER
120 TPH 1-1/2 X 0
HEAVY MEDIA SUMP
141 TPH
REFUSE BIN
REFUSE BELT
61 TPH
REFUSE VACUUM DISC FILTER
10 TPH
STATIC THICKENER 100 FT
10 TPH 28m X 0
10 TPH
TO MAKE-UP WATER
61 TPH
SIEVE BEND
22 TPH
2 TPH
24 TPH
FROTH FLOTATION CELLS
16 TPH 28m X 0
8 TPH
28 X 100m
40 TPH
CLEAN COAL VACUUM DISC FILTER
40 TPH
HEAVY MEDIA CYCLONES
260 TPH
52 TPH
200 TPH
3/4 X 28m
6 X 16 REFUSE SCREEN
52 TPH
6 X 16 CLEAN COAL SCREENS
202 TPH
8 TPH
8 TPH
CENTRIFUGE
1 TPH
51 TPH 3/4 X 28m
4 TPH
CENTRI-FUGE
199 TPH 3/4 X 28m
18 TPH
CLASSIFYING CYCLONES
10 TPH
MAGNETIC SEPARATOR
10 TPH
10 TPH
DILUTE MEDIA SUMP
HEAVY MEDIA SUMP
199 TPH
MAGNETITE THICKENER
30 FT
TO MAKE-UP
TO HEAVY MEDIA CIRCUITS
160 TPH 1-1/2 X 0
359 TPH 1-1/2 X 0
FLUID-BED DRYER
CLEAN COAL BELT
359 TPH
CLEAN COAL STORAGE
35,000 TON CAPACITY

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FIGURE D-9. EXAMPLE 9 - STATE-OF-THE-ART COAL PREPARATION PLANT WITH CONVENTIONAL SINGLE-STAGE FLOTATION

TABLE D-17. EXAMPLE 9 - STATE-OF-THE-ART COAL PREPARATION PLANT WITH CONVENTIONAL SINGLE-STAGE FLOTATION OPERATING & MAINTENANCE PERSONNEL

	Staffing
General Management	
Preparation Superintendent	1
Plant Engineer	1
Total	2
First Shift 7AM - 3PM (All Operating)	
Foreman	1
Plant Operator	1
ROM Operator (Primary Screening & Crushing)	1
Coarse Coal Circuit Operator	1
Fine Coal Circuit Operator	1
Thermal Dryer Operator	1
Thickener Operator	1
Electrician	1
Scraper/Spreader & Wheel Loader Operator (Refuse Loading & Hauling to disposal site)	1
Dozer Operator (Refuse Handling & Compacting)	1
Total	10
Second Shift 3PM - 11PM (3 Hrs Operating - 5 Hrs Maintenance)	
Same staff as First Shift - The various circuit operators have the ability to function as mechanics, welders, etc. to perform the necessary routine repairs, lubrications, adjustments, replacements, etc. during the maintenance portion of the second shift. During major maintenance periods, additional labor is brought in on a temporary basis as needed.	10
Personnel Summary	
General Management	2
First Shift	10
Second Shift	10
Total	22

TABLE D-18. EXAMPLE 9 - STATE-OF-THE-ART COAL PREPARATION PLANT WITH CONVENTIONAL SINGLE-STAGE FLOTATION OPERATING & MAINTENANCE COSTS (Fourth Quarter 1979 Values)

Cost Category	Per Ton Raw Coal	Per Ton Clean Coal
Labor -		
Supervisory	$0.064	$0.089
Operating	0.301	0.419
Maintenance	0.148	0.206
Overhead -		
Employee Benefits, Bonuses, & Indirect Expenses	0.205	0.286
Supplies -		
Operating	0.387	0.539
Maintenance & Other Includes Anti-Freeze Spray used on coal during colder months.	0.188	0.262
Maintenance -		
Motor & Equipment Repair, Etc.	0.511	0.712
Thermal Dryer Fuel -		
Based Upon 2.5 Tons/Hr Coal Consumption & Cost of Coal $26/Ton	0.130	0.181
Electricity -		
Approx. 1/3 associated w/ Thermal Dryer	0.457	0.636
Special Taxes -		
Black Lung & Reclamation	0.349	0.486
Operating & Maintenance Cost -		
Not Including Capital Amortization	$2.74	$3.82
Capital Amortization -		
10 Years - 30% Utilization	$2.06	$2.87
TOTAL OPERATING & MAINTENANCE COST	$4.80	$6.69
Cost Per Million Btu (12,960 Btu/lb)		$0.258

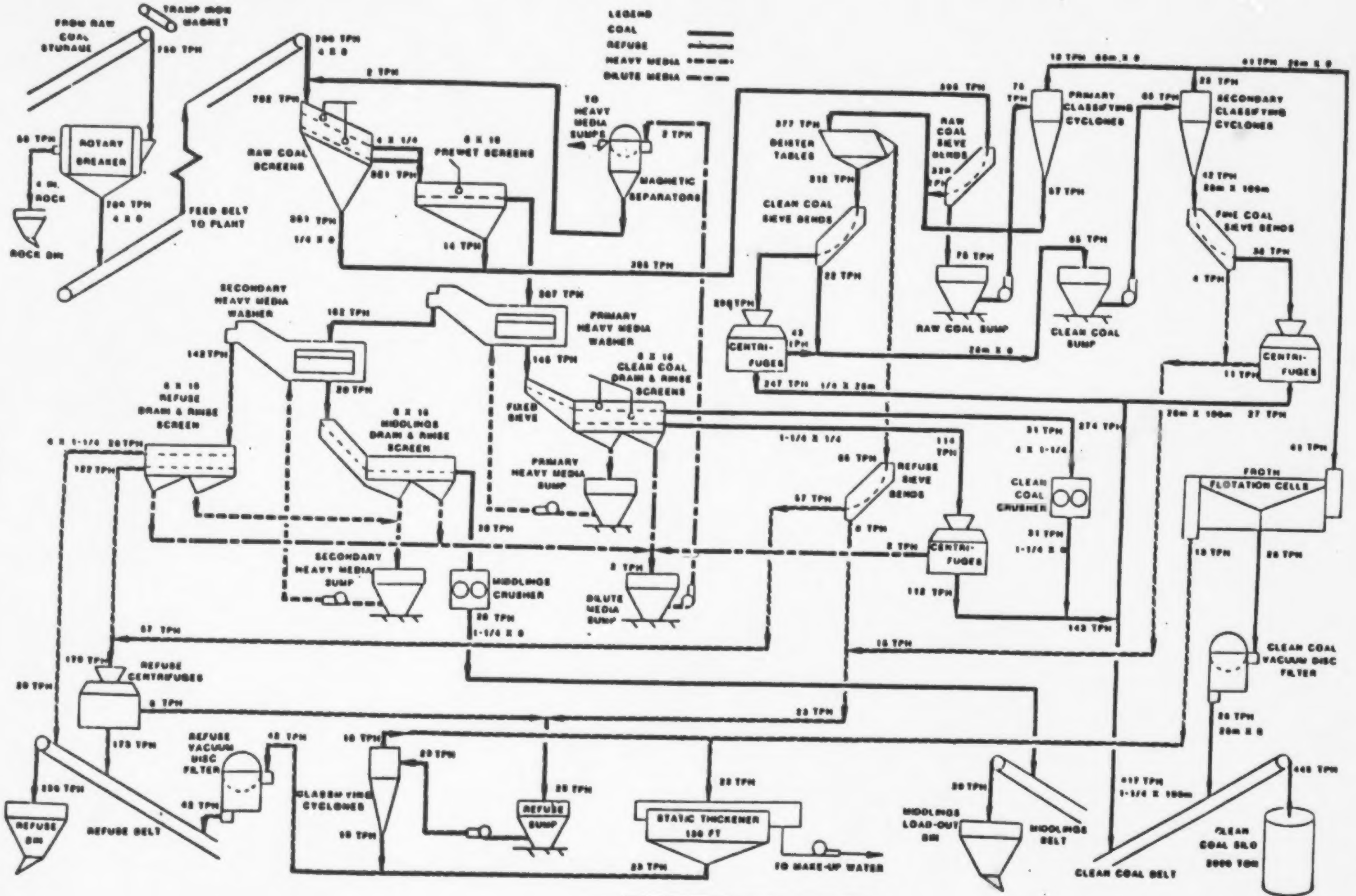
FROM RAW COAL STORAGE
TRAMP IRON MAGNET
750 TPH
60 TPH
ROTARY BREAKER
4 IN. ROCK
ROCK BIN
700 TPH 4 X 0
FEED BELT TO PLANT
700 TPH 4 X 0
702 TPH
2 TPH
RAW COAL SCREENS
4 X 1/4
361 TPH
6 X 10 PREWET SCREENS
361 TPH 1/4 X 0
14 TPH
TO HEAVY MEDIA SUMPS
2 TPH
MAGNETIC SEPARATORS
385 TPH
LEGEND
COAL
REFUSE
HEAVY MEDIA
DILUTE MEDIA
306 TPH
377 TPH
DEISTER TABLES
RAW COAL SIEVE BENDS
329 TPH
312 TPH
CLEAN COAL SIEVE BENDS
22 TPH
78 TPH
RAW COAL SUMP
209 TPH
43 TPH
CENTRI-FUGES
28m X 0
247 TPH 1/4 X 28m
78 TPH
PRIMARY CLASSIFYING CYCLONES
67 TPH
10 TPH 60m X 0
65 TPH
CLEAN COAL SUMP
SECONDARY CLASSIFYING CYCLONES
25 TPH
41 TPH 28m X 0
42 TPH 28m X 100m
FINE COAL SIEVE BENDS
4 TPH
38 TPH
CENTRI-FUGES
11 TPH
28m X 100m
27 TPH
SECONDARY HEAVY MEDIA WASHER
162 TPH
142 TPH
20 TPH
6 X 10 REFUSE DRAIN & RINSE SCREEN
6 X 1-1/4 20 TPH
122 TPH
6 X 10 MIDDLINGS DRAIN & RINSE SCREEN
387 TPH
PRIMARY HEAVY MEDIA WASHER
145 TPH
6 X 10 CLEAN COAL DRAIN & RINSE SCREENS
FIXED SIEVE
PRIMARY HEAVY MEDIA SUMP
20 TPH
SECONDARY HEAVY MEDIA SUMP
MIDDLINGS CRUSHER
20 TPH 1-1/4 X 0
2 TPH
DILUTE MEDIA SUMP
1-1/4 X 1/4
66 TPH
REFUSE SIEVE BENDS
57 TPH
8 TPH
2 TPH
CENTRI-FUGES
112 TPH
114 TPH
31 TPH 4 X 1-1/4
CLEAN COAL CRUSHER
31 TPH 1-1/4 X 0
274 TPH
143 TPH
15 TPH
43 TPH
FROTH FLOTATION CELLS
15 TPH
28 TPH
CLEAN COAL VACUUM DISC FILTER
28 TPH 28m X 0
57 TPH
170 TPH
REFUSE CENTRIFUGES
30 TPH
8 TPH
23 TPH
173 TPH
REFUSE VACUUM DISC FILTER
48 TPH
42 TPH
230 TPH
REFUSE BIN
REFUSE BELT
10 TPH
CLASSIFYING CYCLONES
20 TPH
10 TPH
25 TPH
REFUSE SUMP
23 TPH
STATIC THICKENER 150 FT
23 TPH
TO MAKE-UP WATER
20 TPH
MIDDLINGS LOAD-OUT BIN
MIDDLINGS BELT
417 TPH 1-1/4 X 100m
CLEAN COAL BELT
445 TPH
CLEAN COAL SILO 2000 TON

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FIGURE D-10. EXAMPLE 10 - STATE-OF-THE-ART COAL PREPARATION PLANT WITH CONVENTIONAL SINGLE-STAGE FLOTATION

TABLE D-19. EXAMPLE 10 - STATE-OF-THE-ART COAL PREPARATION PLANT WITH CONVENTIONAL SINGLE-STAGE FLOTATION OPERATING AND MAINTENANCE PERSONNEL

General Management		Staffing
Preparation Plant Superintendent		1
Maintenance Superintendent		1
	Total	2
First & Second Shifts (All Operating)		
Foreman		1
Control Room Operator (Plant Operator)		1
Gravity Operator (Coarse Coal Operator)		1
Fine Coal Operator		1
Filter Operator (Clean Coal & Refuse)		1
Electrician		1
Mechanic		1
Utility Man		1
Truck Driver (Refuse Hauling)		3
Dozer Operator (Refuse Spreading & Compacting)		1
Weighman	Located at Raw Coal Storage Bins	1
Bin Attendant		1
Clean Coal Silo Attendant		2
	Total	16
Third Shift (All Maintenance)		
Foreman		1
Electrician		1
Mechanic		4
Welder		2
Greaser		1
	Total	9
Personnel Summary		
General Management		2
Operating Shifts		32
Maintenance Shift		9
	Total Plant Staff	43

TABLE D-20. EXAMPLE 10 - STATE-OF-THE-ART COAL PREPARATION PLANT WITH CONVENTIONAL SINGLE-STAGE FLOTATION OPERATING AND MAINTENANCE COSTS

Cost Category	Per Ton Raw Coal	Per Ton Clean Coal
Labor -		
General Management	$0.028	$0.042
Operating	0.317	0.477
Maintenance	0.089	0.134
Overhead - Includes Payroll Taxes, Insurance Vacation, Holidays, and Other Fringe Benefits	0.226	0.340
Taxes and Insurance	0.070	0.105
Operating Supplies and Expense -		
General	0.347	0.522
Magnetite & Chemicals - Including flocculants, scale & corrosion control, frother, promoter, caustic, freeze proofing, etc.	0.218	0.328
Maintenance Supplies and Expense	0.398	0.599
Refuse Handling Equipment Repair & Expense	0.109	0.164
Electricity	0.214	0.322
Black & Clean Water Treatment	0.135	0.203
Labor & Analysis	0.106	0.160
Miscellaneous - Including Refuse & Reclamation, Fuels	0.089	0.134
Operating & Maintenance Cost - Not Including Capital Amortization	$2.35	$3.53
Capital Amortization - 10 Years - 35% Utilization	$1.26	$1.90
TOTAL OPERATING & MAINTENANCE COST	$3.61	$5.43
Cost Per Million Btu (13,134 Btu/lb)		$0.207

APPENDIX E

FLOW SHEETS FOR GENERIC CLEANING PLANT CONFIGURATIONS

TABLE E-1. EQUIPMENT IDENTIFICATION LIST FOR FIGURES 6C-1 THROUGH 6C-5.

A. Screen
B. Crusher
C. Sieve Bend
D. Dense Medium Vessel
E. Dense Medium Cyclone
F. Jig (water)
G. Concentrating Table
H. Froth Flotation Cells
I. Dense Medium Recirculation System
J. Dense Medium Distributing Tank
K. Filter
L. Thickener
M. Head Tank
N. Sump with Pump
O. Centrifuge

On Figures 6C-1 through 6C-6 equipment identification is via letter; e.g. A. indicates screen.

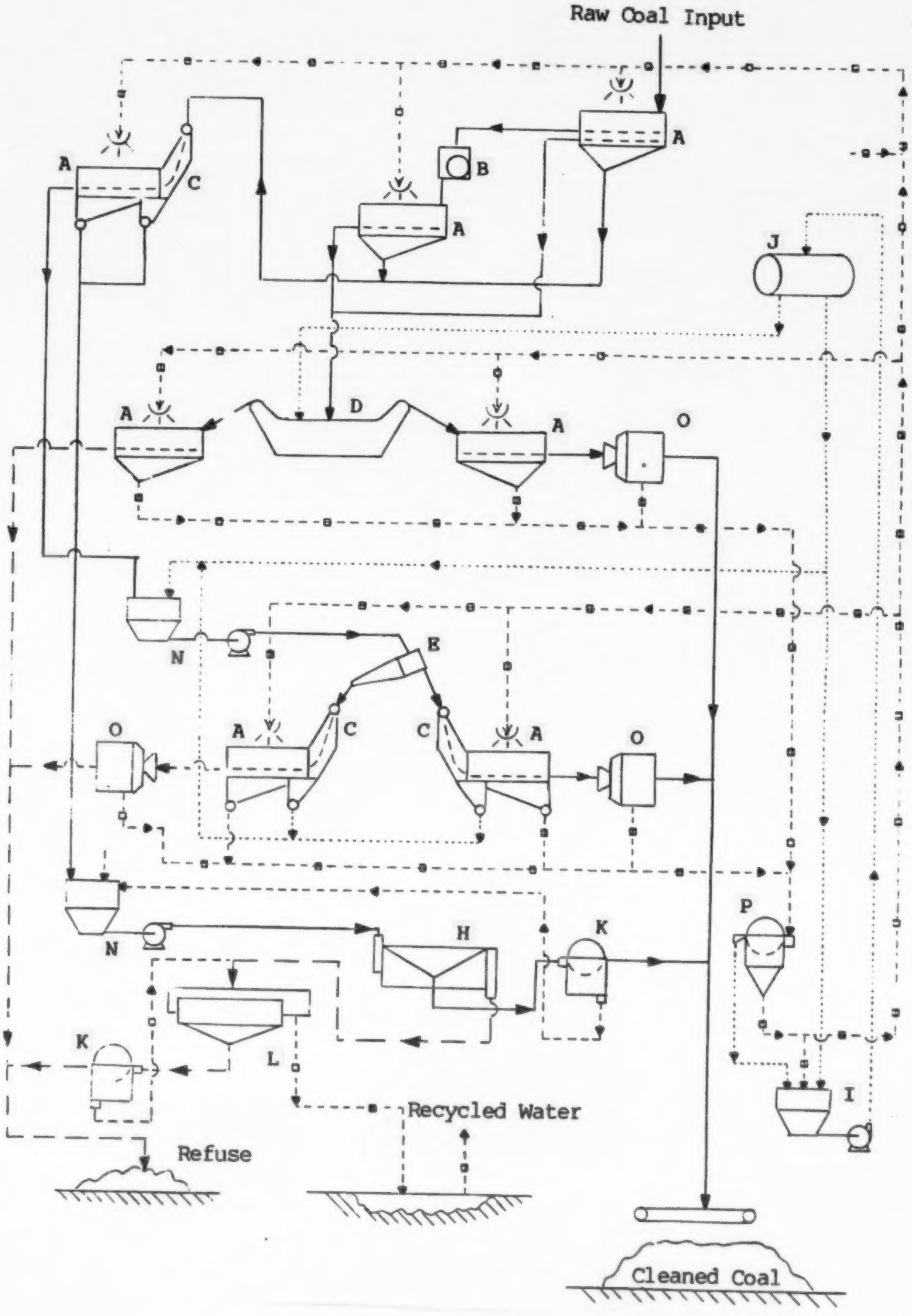
Raw Coal Input
A
B
C
A
A
J
A
D
A
O
N
E
O
A
C
C
A
O
N
H
K
P
K
L
I
Recycled Water
Refuse
Cleaned Coal

FIGURE E-1. GENERIC FLOW DIAGRAM,
H.M. VESSEL, D.M. CYCLONE, FROTH FLOTATION

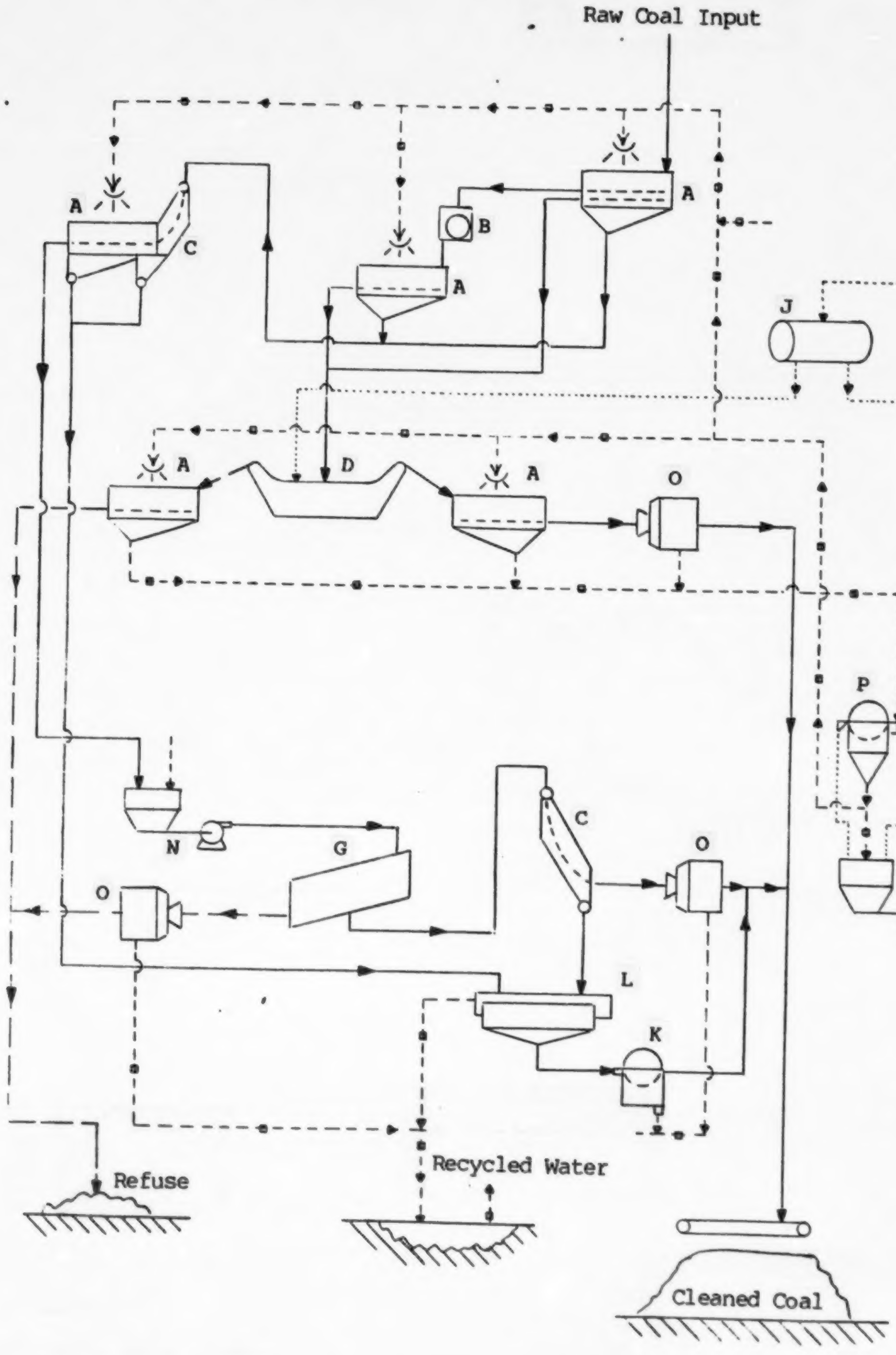
Raw Coal Input
A
A
B
C
A
J
A
D
A
O
P
N
G
C
O
O
L
K
Refuse
Recycled Water
Cleaned Coal

FIGURE E-2. GENERIC FLOW DIAGRAM, H.M. VESSEL, CONCENTRATING TABLE

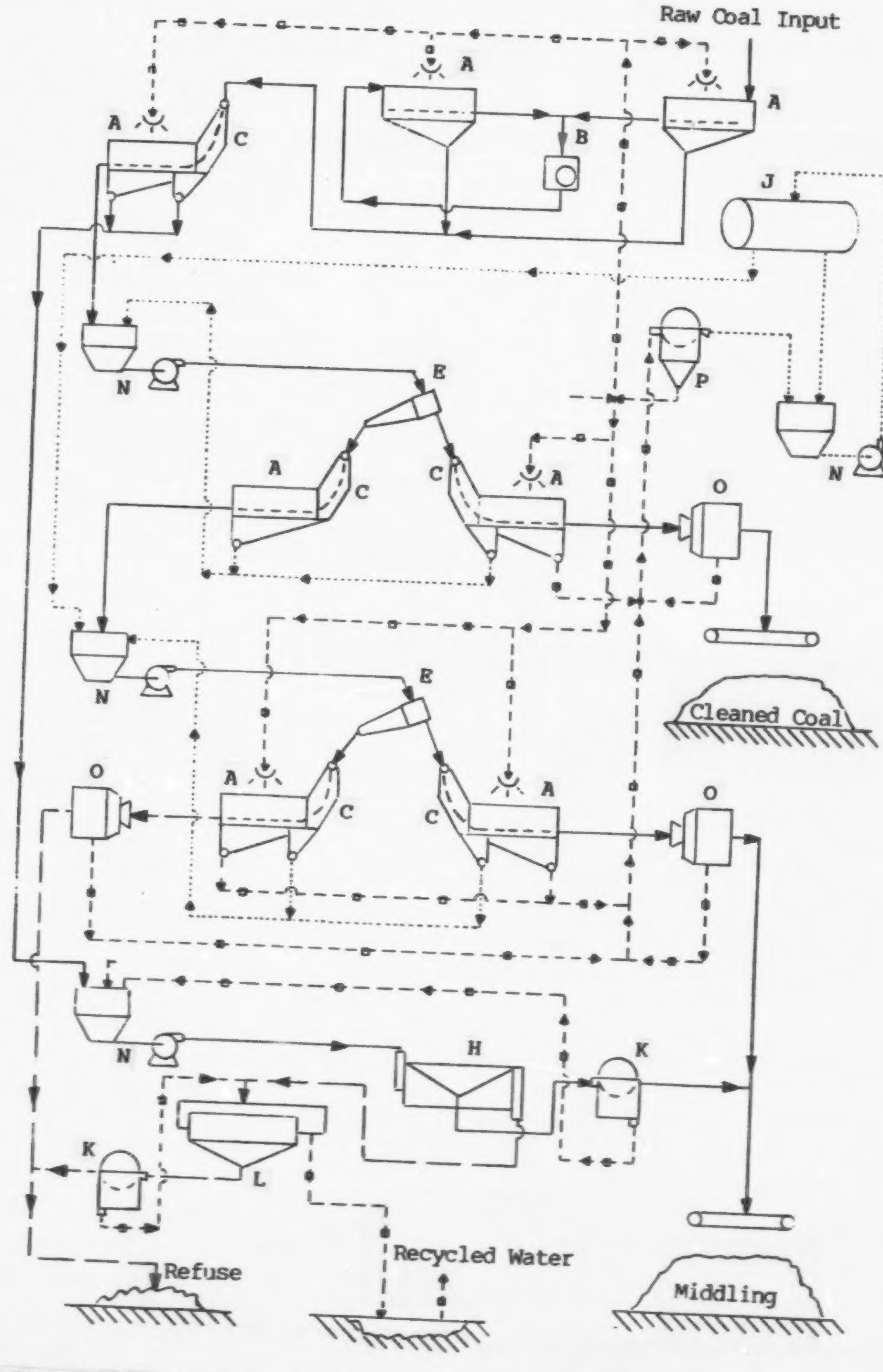
Raw Coal Input
A
A
A
B
C
J
E
P
N
N
A
C
C
A
O
E
N
Cleaned Coal
O
A
C
C
A
O
N
H
K
K
L
Refuse
Recycled Water
Middling

FIGURE E-3. GENERIC FLOW DIAGRAM, D.M. CYCLONES, FROTH FLOTATION

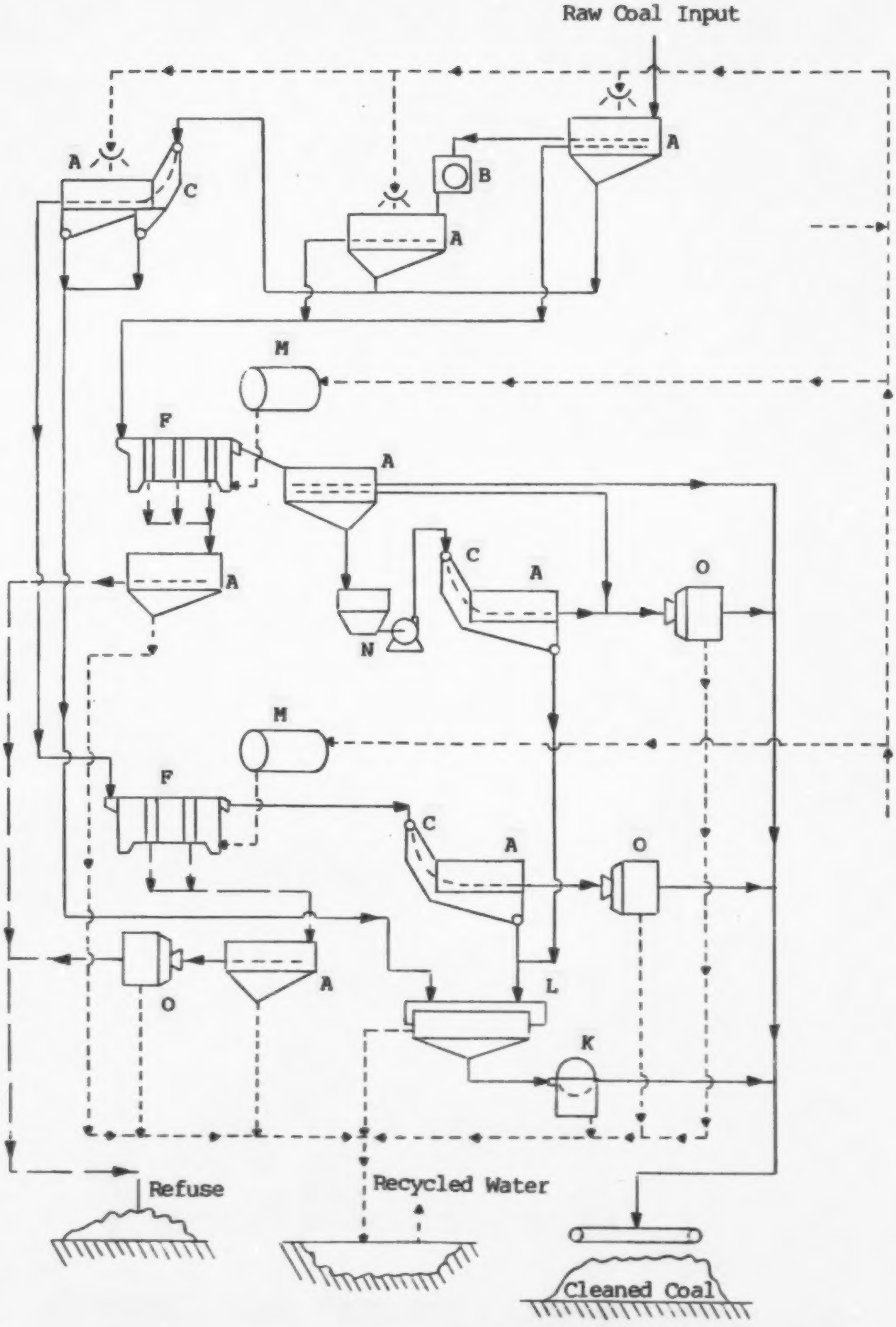
Raw Coal Input
A
B
A
C
A
M
F
A
A
C
A
O
N
M
F
C
A
O
O
A
L
K
Refuse
Recycled Water
Cleaned Coal

FIGURE E-4. GENERIC FLOW DIAGRAM, JIG PLANT

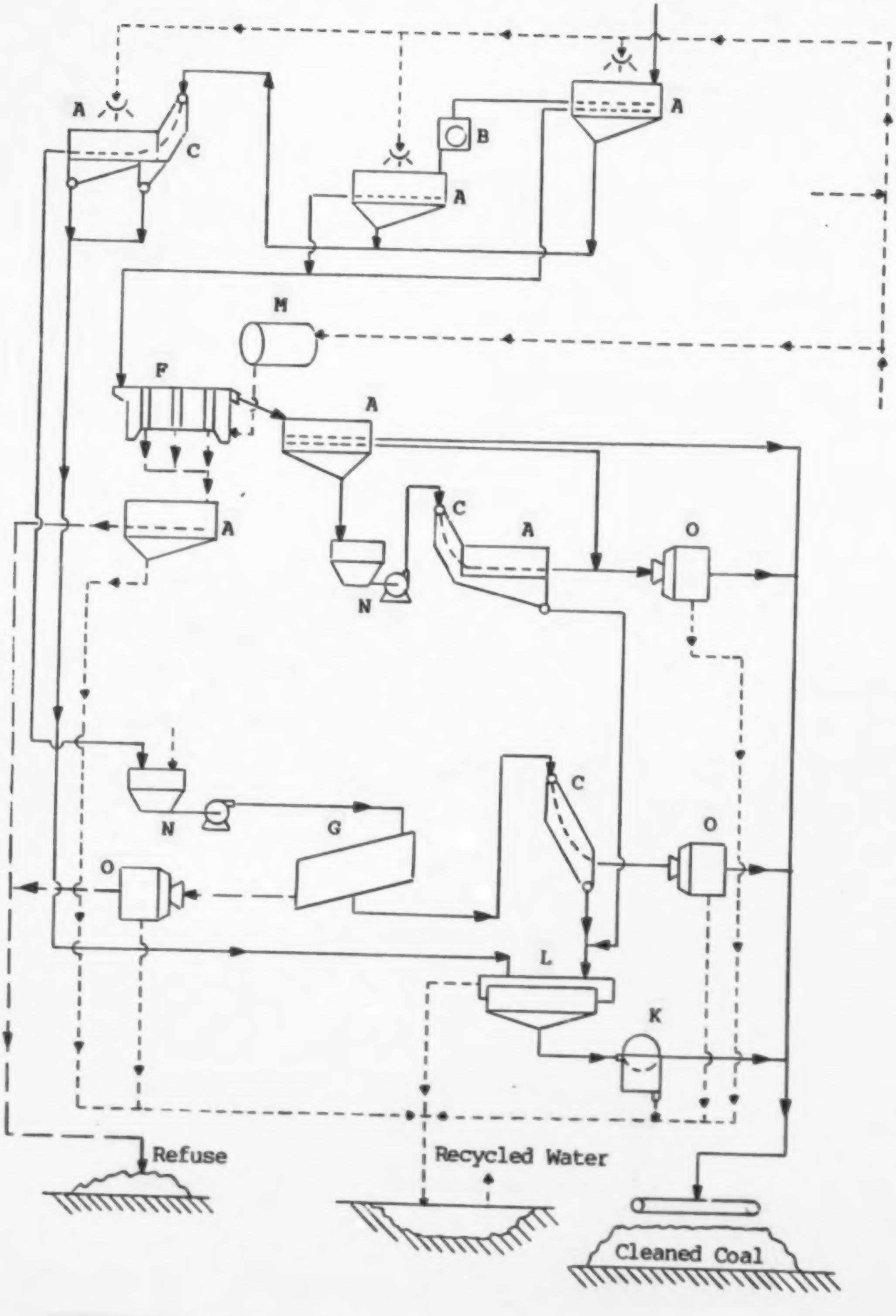
A
C
B
A
A
M
F
A
A
C
A
O
N
C
N
G
O
O
L
K
Refuse
Recycled Water
Cleaned Coal

FIGURE E-5. GENERIC FLOW DIAGRAM, JIG, CONCENTRATING TABLE

APPENDIX F

COAL UTILIZATION TABLES

Table F-1. Coal Utilization - K=1.00
(10^{13} Btu output/year)

Coals	Boilers 1	2	3	4	5	6	Total
1							
2							
3	0.370	1.038	0.432	0.033	0.083		1.956
4							
5	0.840						0.840
6							
7							
8							
9							
10						0.788	0.788
11					2.415	1.226	3.641
12	0.486						0.486
							7.711

Table F-2. Coal Utilization - K=0.95
(10^{13} Btu output/year)

Coals	Boilers 1	2	3	4	5	6	Total
1							
2							
3	0.370	1.038	0.432	0.033	0.083		1.956
4							
5	0.440						0.440
6							
7							
8							
9							
10						0.788	0.788
11					2.415	1.226	3.641
12	0.886						0.886
							7.711

Table F-3. Coal Utilization - K=0.90
(10^{13} Btu output/year)

	Boilers						
Coals	1	2	3	4	5	6	Total
1							
2							
3	0.370	1.038	0.432	0.033	0.083		1.956
4							
5	0.085						0.085
6							
7							
8							
9							
10						0.788	0.788
11					2.415	1.226	3.641
12	1.241						1.241
							7.711

Table F-4. Coal Utilization - K=0.85
(10^{13} Btu output/year)

	Boilers						
Coals	1	2	3	4	5	6	Total
1							
2							
3	0.128	1.038	0.432	0.033			1.631
4							
5							
6							
7							
8							
9							
10						0.788	0.788
11	0.051				2.498	1.226	3.775
12	1.517						1.517
							7.711

Table F-5. Coal Utilization - K=0.80
(10^{13} Btu output/year)

Coals	Boilers 1	2	3	4	5	6	Total
1							
2							
3		0.934	0.432	0.033			1.399
4							
5							
6							
7							
8							
9							
10						0.788	0.788
11	0.351				2.498	1.226	4.075
12	1.345	0.104					1.449
							7.711

Table F-6. Coal Utilization - K=0.75
(10^{13} Btu output/year)

			Boilers				
Coals	1	2	3	4	5	6	Total
1							
2							
3		0.403	0.432	0.033			0.868
4							
5							
6							
7							
8		0.464					0.464
9							
10						0.788	0.788
11	0.351				2.498	1.226	4.075
12	1.345	0.171					1.516
							7.711

Table F-7. Coal Utilization - K=0.70
(10^{13} Btu output/year)

	Boilers						
Coals	1	2	3	4	5	6	Total
1							
2							
3			0.374	0.033			0.407
4							
5							
6							
7							
8		0.867					0.867
9							
10						0.788	0.788
11	0.351		0.058		2.498	1.226	4.133
12	1.345	0.171					1.516
							7.711

Table F-8. Coal Utilization - K=0.65
(10^{13} Btu output/year)

Coals	Boilers						
	1	2	3	4	5	6	Total
1							
2							
3			0.066				0.066
4				0.029			0.029
5							
6							
7							
8		0.894	0.078				0.972
9				0.004			0.004
10						0.788	0.788
11	0.351	0.144	0.117		2.498	1.226	4.336
12	1.345	0.171					1.516
							7.711

Table F-9. Coal Utilization - K=0.60
(10^{13} Btu output/year)

Coals	Boilers						
	1	2	3	4	5	6	Total
1							
2							
3							
4							
5							
6							
7							
8	0.044	0.792	0.111				0.947
9				0.001			0.001
10		0.246		0.006	0.881	0.788	1.921
11	0.363		0.120		1.617	1.226	3.326
12	1.289		0.201	0.026			1.516
							7.711

Table F-10. Coal Utilization - K=0.55
(10^{13} Btu output/year)

Coals	Boilers						
	1	2	3	4	5	6	Total
1							
2							
3							
4							
5							
6							
7							
8	0.044	0.792	0.111				0.947
9				0.001			0.001
10		0.246		0.006	2.498	0.910	3.660
11	0.363		0.120		1.617	1.104	1.587
12	1.289		0.201	0.026			1.516
							7.711

Table F-11. Coal Utilization - K=0.50
(10^{13} Btu output/year)

Coals	Boilers 1	2	3	4	5	6	Total
1							
2							
3							
4							
5							
6							
7							
8	0.275	0.792	0.184	0.013			1.264
9							
10	0.064	0.246	0.030	0.008	2.498	2.014	4.860
11	0.342		0.101				0.443
12	1.015		0.117	0.012			1.144
							7.711

Table F-12. Coal Utilization - K=0.48
(10^{13} Btu output/year)

Coals	Boilers 1	2	3	4	5	6	Total
1							
2							
3							
4							
5							
6							
7							
8	0.625	0.792	0.184	0.013			1.614
9							
10	0.202	0.246	0.030	0.008	2.498	2.014	4.998
11	0.257		0.101				0.358
12	0.612		0.117	0.012			0.741
							7.711